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Audits of entities with oil and gas producing activities with conforming changes as of May 1, 1999; Audit and accounting guide:

American Institute of Certified Public Accountants. Oil and Gas Committee

AICPA AUDIT AND ACCOUNTING GUIDE

AICPA

AMERICAN INSTITUTE OF CERTIFIED PUBLIC ACCOUNTANTS

AUDITS OF ENTITIES WITH OIL AND GAS PRODUCING ACTIVITIES

With Conforming Changes as of May 1, 1999

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Audits of Entities With Oil and Gas Producing Activities

With Conforming Changes as of May 1, 1999

This edition of the AICPA Audit and Accounting Guide *Audits of Entities With Oil and Gas Producing Activities*, which was originally issued in 1986, has been modified by the AICPA staff to include certain changes necessary because of the issuance of authoritative pronouncements since the Guide was originally issued (see page iv). The changes made are identified in a schedule in appendix D of the Guide. The changes do *not* include all those that might be considered necessary if the Guide were subjected to a comprehensive review and revision.

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NOTICE TO READERS

This audit and accounting guide presents recommendations of the AICPA Oil and Gas Committee on the application of generally accepted auditing standards to audits of financial statements of entities with oil and gas producing activities. This guide also presents the committee's recommendations on and descriptions of financial accounting and reporting principles and practices for entities with oil and gas producing activities. The AICPA Accounting Standards Executive Committee and members of the AICPA Auditing Standards Board have found this guide to be consistent with existing standards and principles covered by Rules 202 and 203 of the AICPA Code of Professional Conduct. AICPA members should be prepared to justify departures from this guide.

This guide reflects relevant guidance contained in authoritative pronouncements through May 1, 1999:

FASB Statement No. 134, *Accounting for Mortgage-Backed Securities Retained after the Securitization of Mortgage Loans Held for Sale by a Mortgage Banking Enterprise* (an amendment of FASB Statement No. 65)

FASB Interpretation No. 42, *Accounting for Transfers of Assets in Which a Not-for-Profit Organization Is Granted Variance Power*

FASB Technical Bulletin 97-1, *Accounting under Statement 123 for Certain Employee Stock Purchase Plans with a Look-Back Option*

EITF Consensuses adopted through the January 1999 Emerging Issues Task Force (EITF) meeting

Practice Bulletin 15, *Accounting by the Issuer of Surplus Notes*

SAS No. 87, *Restricting the Use of an Auditor's Report*

SOP No. 98-9, *Modification of SOP 97-2,* Software Revenue Recognition, *With Respect to Certain Transactions*

SSAE No. 9, *Amendments to Statement on Standards for Attestation Engagements Nos. 1, 2, and 3*

Preface

This guide describes relevant matters unique to the oil and gas producing industry in order to assist the independent auditor in auditing and reporting on financial statements of entities performing these activities.

Generally accepted auditing standards and accounting principles are applicable in general to the oil and gas producing industry. The general application of those standards and principles is not discussed herein; rather, this guide focuses on the special problems inherent in auditing and reporting on the financial statements of an entity with oil and gas producing activities.

The guide concentrates on the domestic exploration and production activities of oil and gas companies and generally does not address the special problems related to other activities of integrated oil and gas companies or foreign activities. The guide also does not differentiate between onshore and offshore activities because their financial accounting considerations are similar.

The guide provides information regarding statutory rules and regulations applicable to the industry. Also included are illustrations of the form and content of financial statements for entities with oil and gas producing activities. Rules and regulations, as well as applicable authoritative accounting and auditing pronouncements, are subject to change and revision. Therefore, the auditor should keep abreast of developments affecting these items.

The guide contains certain suggested auditing procedures, but detailed internal control questionnaires and audit programs are not included. The nature, timing, and extent of auditing procedures are a matter of professional judgment and will vary depending on the size, organizational structure, existing internal control, and other factors in a particular engagement.

The accounting principles described in this guide are limited to the successful efforts method specified by Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, and the full cost method specified by the Securities and Exchange Commission (SEC) in Regulation S-X. This guide is intended only to provide an overview of the accounting principles and the current SEC regulations, but the Bibliography contains extensive references that include more in-depth discussions of accounting principles and SEC regulations. It should be recognized that hybrids of both of these methods are commonly referred to by those names and are often considered to be within the framework of generally accepted accounting principles for companies not reporting to the SEC. FASB Statement No. 25, *Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies,* suspended the effective date specified by FASB Statement No. 19 for requiring the successful efforts method of accounting. However, the FASB Statement maintains that for purposes of applying paragraph 16 of APB Opinion No. 20, *Accounting Changes,* the successful efforts method is preferable for accounting for oil and gas producing activities. As a consequence, no justification for a change to the successful efforts method is necessary nor is a preferability letter for such a change required by the SEC for its registrants. Any change to the full cost method must be justified as being preferable in the circumstances, and a preferability letter describing those circumstances must be filed with the SEC by registrants.

Effective Date

The provisions of this guide shall be effective for audits of financial statements for periods ending on or after December 31, 1986.

Oil and Gas Committee

Note: The guide has not been expanded to include other practices followed by some private companies.

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Chapter 1

Overview of the Oil and Gas Industry

The Industry's History

1.01 To gain an understanding of oil and gas producing activities, a brief review of the history of the industry and oil and gas accounting is helpful. The following discussion is intended to be basic in nature, but additional references are included in the bibliography section. (The interested reader is urged to refer to other available sources.)

1.02 The first commercial oil-drilling venture was in 1859 near Titusville, Pennsylvania. A steam-powered, cable-tool drilling rig was used to drill a fifty-nine-foot well, which yielded five barrels of oil per day. This well set off a boom of sorts, and the cable-tool rig—which at that time was revolutionary—was used to drill other wells in the area. Oil soon sold for about ten cents a barrel because of the dramatic increase in supply.

1.03 In the 1850s and early 1860s, oil was chiefly used for lamp fuel. The Industrial Revolution and the Civil War greatly increased the uses of oil and therefore the demand—so much so that annual production in 1870 exceeded twenty-five million barrels. Early transportation of crude oil was cumbersome, however, requiring (1) wooden barrels (each with a capacity of forty-two gallons—the present measurement of a barrel of crude oil), (2) horse-drawn wagons, (3) river barges, and (4) the railroads. The first pipeline, completed in the 1860s, was made of wood and was less than one-thousand feet long.

1.04 One of the first to rise to power in this infant industry was John D. Rockefeller. In 1870, Rockefeller merged his firm with four others to form the Standard Oil Company. During the 1880s, Standard Oil controlled approximately 90 percent of the refining industry in the United States. Standard Oil's market dominance eventually led to its forced dissolution in 1911-1915 because of federal and state antitrust legislation that had been enacted as a response to its size.

1.05 The growing number of automobiles steadily increased the demand for oil. Because a domestic shortage was feared by the U.S. government, the industry was encouraged to increase foreign exploration. In the 1920s, exploration in the Middle East, South America, Africa, and the Far East had begun. However, the east Texas oil field discovery of 1930 ultimately created an oil surplus that caused companies to cut back foreign operations. During and after World War II, however, demand again increased, and enormous capital investments developed the Persian Gulf area. This period also saw an increased use of natural gas, facilitated by improved transportation systems, and the growth of the petrochemical industry (which produced plastics and synthetics).

1.06 The oil and gas industry has gone through many changes in the past twenty years. The Arab oil embargo of 1973 focused public attention and criticism on the industry, partly because of the embargo's effect on previously stable prices. (In 1973, before the embargo, the average barrel of crude oil sold for about three dollars.) Nearly half the oil used by the United States in 1977 was imported. In 1979, the government announced "phased decontrol" of oil prices on a schedule that would have freed all crude prices by October 1981; however, in January 1981, all price controls on crude oil were immediately lifted. Natural gas prices continued to be subject to controls, as required by the Natural Gas Policy Act of 1978, but initial deregulations began January 1, 1985.

1.07 By the early 1980s, the price for a barrel of oil ranged from thirty to forty dollars (and sometimes higher), representing an approximate 1000-percent increase in less than ten years. In the mid-1980s, however, prices had declined in the face of a world oil surplus. The effects of these fluctuations were further complicated by U.S. government price controls that designated different grades of oil and created a complex pricing structure. As a result, producing companies grew increasingly reluctant to explore and drill. This reluctance may have stemmed from the fact that a barrel of domestically produced oil often had a sale price significantly less than the price of imported oil.

Types and Sizes of Companies in the Industry

1.08 Companies engaged in oil gas exploration and production are characterized by a wide diversity in type and size; ultimately, most are primarily dependent on their success in exploring for and developing oil and gas reserves. Companies in the industry range from the largest corporations in the world to very small companies or proprietorships with limited sales and resources.

1.09 The organization of oil and gas companies varies depending on size and diversity of activities. Oil and gas producers are usually classified as independent or integrated companies. A fully integrated company produces oil and gas and also operates refineries, pipelines, and wholesale and retail outlets. Some companies are only partially integrated.

1.10 Independent exploration and production companies generally do not refine products or engage in marketing activities. They limit their activities to exploration, development, and production.

1.11 Discussions in this guide will concentrate on the oil gas exploration and production activities of both independent and integrated oil and gas operations. These activities include acquisition of mineral properties, exploration, drilling and development, and production.

Ownership Interests and Operations

1.12 The characteristics relatively unique to oil and gas operations are the normal existence of multiple ownerships of individual properties and the varying types of ownership interests. This variety of ownership interests has developed in response to the need to share risks, to take advantage of tax opportunities, and to raise the large amounts of capital necessary. The principal types of ownership or economic interests encountered in the industry will be discussed, but variations of these will be encountered because of the easily divisible nature of oil and gas operations.

Types of Interests

1.13 *Mineral interest* is the complete ownership of the minerals in place.

1.14 *Royalty interest* is the portion of the mineral interest retained by the lessor. This interest entitles the royalty interest owner to a fractional amount of the production from the property, in kind or in value, less the applicable severance and the windfall profit taxes. Occasionally, the royalty interest may bear certain specific costs.

1.15 *Working interest* (or *operating interest*) is the interest in the oil and gas in place that bears most or all of the cost of development and operation of the property. Mineral interest revenues minus the royalty interest equals the working interest share of revenues.

1.16 *Overriding royalty* is a royalty interest that is created out of the working interest. Its term is coextensive with that of the working interest from which it was created.

1.17 *Net profits interest* is an interest in production created from the working interest and measured by a certain percentage of the net profits (as defined in the contract) from the operation of the property.

1.18 *Retained interest* is an interest that arises when the working interest owner transfers the basic rights and responsibilities for developing and operating the property to another party and retains a special nonoperating interest created by the conveyance contract.

1.19 *Carved-out interest* is an interest created when the working interest owner retains the basic working interest but grants to another entity special nonoperating rights and obligations.

Joint Interest Operations

1.20 *Operating Agreements.* Joint interest (also referred to as "joint venture") operations result from an agreement among two or more working interest owners whereby one party is designated as the operator for the development and operation of the jointly owned property included in the joint venture. In joint interest operations, each working interest owner retains an undivided interest in the jointly operated property. This direct ownership is usually included in the financial statements of the investor through direct inclusion of its proportional share of the expenses, revenues, and assets. Joint interest operations are designed to accomplish the objectives of sharing risk, obtaining capital, maximizing efficiency of development and operations, and enhancing the recovery of reserves.

1.21 Joint interest operations are governed by complex operating agreements that set forth the rights, duties, and obligations of each party. A significant part of the agreement is the accounting procedure section, which establishes the basis for charges and credits to the operator and the nonoperating parties and provides for billings, advance of funds, payment schedules, audits, and other general provisions of the arrangement. The accounting provisions in joint operating agreements usually follow a model provision devised by the Council of Petroleum Accountants Societies (COPAS). Although the lease is usually considered the accounting unit, many costs cannot be directly identified with a particular lease. Such costs are usually categorized as indirect expenses and are recovered by allocating overhead to leases on some reasonable basis. These costs include service unit costs and certain types of overhead.

1.22 The operator bills the nonoperators (usually at the end of each month) for their share of the month's expenditures. The billing is referred to as a joint interest billing (JIB). The operator may also make a cash call at the beginning of each month for the nonoperator's share of anticipated expenditures that will be incurred during the month. In some cases, the operator may also collect revenues from production of crude oil and other liquids and distribute the proceeds to the various ownership interests, although in many cases the purchaser will pay the various interests directly based on the division order. Normally, purchasers of natural gas remit revenues directly to working interest owners in accordance with purchaser agreements negotiated with each working interest owner.

1.23 Most large oil and gas companies, as well as many smaller companies, act as operators on a number of the oil and gas properties in which they have an interest. It should be recognized, however, that nearly all companies will be nonoperators with respect to a significant portion of their properties. In addition, the extent to which nonoperators take an active role in the operation of properties varies widely in practice. In many instances, the nonoperator maintains full accountability for activities on the properties, including advance authorization of capital expenditures through the authorization for expenditure (AFE) process and review and approval of revenue and expense transactions. In other instances, nonoperators may rely almost entirely on the operator for recording transactions and maintaining accountability and receive only a summary report of activity. The degree of actual involvement in practice may fall anywhere within this range.

1.24 *Joint Interest Audits.* The accounting procedure section of the operating agreement usually contains a provision that establishes the timing of the auditing of the operator's records by the nonoperating parties. Under some of the accounting procedures, the nonoperators may audit the operator's expenditures within two years after the end of the period to be audited. If such an option is not exercised, or if an exception is not granted in advance, the nonoperator would be precluded from conducting a subsequent audit and all transactions billed would be considered correct.

1.25 In some of the older agreements, provisions existed where the nonoperator was permitted much less time to conduct an audit (for example, a six-month constraint was not unusual).

1.26 Joint interest audits are normally conducted by the nonoperator's internal auditors or by independent auditors hired by the nonoperator. The purpose—and therefore the scope—of joint interest audits is significantly different from an audit of financial statements in accordance with generally accepted auditing standards. Such audits are beyond the scope of this guide; however, the independent auditor should realize there are no generally recognized joint interest audit standards in existence. The quality of joint interest audits may vary significantly. (See the Bibliography for COPAS bulletins.)

1.27 *Division Orders.* Contractual agreements among the parties determine ownership interests, and rarely are two contracts exactly the same. In almost every case there will be at least two recipients of production proceeds: the working interest owner and the royalty owner. Thus, a division-of-interest order (or simply division order) is prepared to indicate the proper distribution of production proceeds.

1.28 A regular division order is an agreement between the purchaser of production and all the various owners of interests in the property. This agreement includes the following: (1) the legal description of the property; (2) the owners of interests in the property; (3) the interest owned by each; and (4) the terms of purchase, including provisions dealing with passage of title, price, measurement, production taxes, and related items. The operator of the property circulates the division order to the various owners of interest. Each owner, by signing the division order, does the following: represents ownership to be as stated; authorizes the purchaser to receive production from the property and to make payment to the owners in proportion to their respective interests; and agrees to all other provisions of the division order. Sometimes the operator receives the full payment from the purchaser and makes the distribution to the other owners.

1.29 In the event that an owner of interest is unknown or cannot be located and the signature cannot be secured on the division order, the revenue applicable to that interest is held in suspense. In a similar manner, revenue is held in suspense pending receipt of proof of title or title opinion, execution of the division order, or litigation to resolve a dispute over ownership of an interest.

Sources of Capital

1.30 Oil and gas producing companies require enormous amounts of capital, especially in their exploration and development activities. As in most industries, the traditional sources of capital are internal financing and equity and other forms of external financing. However, the various and sometimes unique adaptations in the oil and gas industry warrant discussion.

1.31 In the past, oil and gas companies, especially those that were large and financially strong, were able to fund a large amount of their exploration and development activities with internally generated funds. Increased competition among companies for exploration rights to undeveloped properties as well as rising acquisition and development costs have resulted in companies turning more frequently to other sources of funds.

Joint Interests

1.32 Companies often enter into arrangements with others as a means of raising or sharing capital. This can be done by creating joint ventures or partnerships, but is often accomplished by transferring a portion of the working interest to other parties, as discussed more thoroughly under "Conveyances" in paragraphs 2.120 through 2.131. Depending on the attractiveness of the property and the owner's willingness to dilute interest, a portion of the costs of a property may be financed in this manner. An example of a common deal at one time in the industry was a "third for a quarter," in which the purchaser agreed to assume a third of the costs in exchange for a fourth of the working interest in the property. Another example is a carried interest arrangement, in which one party agrees to develop and operate a property at its costs but maintains the right to recapture its costs or a defined greater amount from the proceeds of production.

Limited Partnerships

1.33 It is common for oil and gas operators to organize limited partnerships. These partnerships are commonly called "oil and gas funds" or "oil and gas programs." Limited partnerships are organized by a sponsor who sells interests in the partnership to private investors and then acts as the general partner when the partnership has been organized. In the past limited partnerships were usually structured to maximize the tax deductions passed through to the limited partners. The limited partners are usually liable only for the amount of their contribution to the partnership. The general partner normally has unlimited liability for the debts and obligations above the limited partners' capital; however, the general partner has full control over the partnership's operations.

1.34 The partnerships typically are either drilling funds or production funds. Drilling funds are organized to finance exploration of new prospects, while production funds are invested only in properties known to contain oil or gas.

1.35 The limited partnership is governed by the partnership agreement, which explains the rights and obligations of the partners. The partnership agreement specifies the method of allocating revenues and expenses between the general and limited partner interests. The basic allocation methods are functional allocation, reversionary interest, promoted interest, and carried interest. The limited partner should look to the substance of the transaction for the proper accounting treatment. Methods for special allocation of profits and costs for tax purposes may be inappropriate for financial reporting purposes.

1.36 Functional allocation usually provides for the tax-deductible expenses to be paid with the limited partners' contribution and allocated to them. Capital expenditures such as leasehold costs and equipment are paid with the general partners' contribution. Revenue sharing is based on a predetermined percentage ratio between the general and limited partners. This method normally achieves the fastest deduction of costs for the limited partners.

1.37 Under a reversionary interest allocation, the limited partners' contribution is used to pay the largest percentage of the partnership expenses, and the limited partners receive a high percentage of the revenues until they recover their initial capital contributions. After the limited partners recover their initial investment, the allocation reverts to another percentage ratio assigning a larger portion of revenues and expenses to the general partner interest.

1.38 In a promoted interest program, the general partner pays a specified percentage of all costs and receives a disproportionately larger percentage of net revenues.

1.39 In a carried interest program, the general partner pays a specified percentage of operating costs and receives a specified percentage (often larger) of revenues but does not bear any capital costs.

1.40 Aside from the differences in the equity section of the financial statements and the allocation of revenues and costs between the general and limited partners, which is dictated by the partnership agreement, the accounting for and the auditing of an oil and gas limited partnership are basically the same as for any other oil and gas producer. However, financial statements are often prepared on either the income tax or cash basis, except for those of public limited partnerships, which are required to be prepared on the basis of generally accepted accounting principles. This guide does not discuss the income tax or cash basis financial statements of limited partnerships—nor does it address financial accounting and auditing considerations that may be unique to limited partnerships.

Other Sources of Capital

1.41 Quite common are production payment transactions, whereby a lender advances funds to be repaid from future production. Short-term as well as long-term financing from banks often takes the form of production loans, secured by specific, producing mineral properties. The auditor should be aware of the potential implications of the different forms of financing.

Accounting for Oil and Gas Producing Activities

1.42 The two primary accounting methods followed by oil and gas producers are the successful efforts method and the full cost method. Successful efforts accounting essentially provides for capitalizing only those costs directly related to proved properties; it then amortizes those costs over the life of the properties.

1.43 Prior to the mid-1950s, most oil and gas companies used the successful efforts accounting method or some variation thereof. In the mid-1950s, a form of the full cost method of accounting was introduced.

1.44 The full cost concept became popular with small, newly formed companies. It allowed them to defer their early costs until successful exploration produced offsetting revenue. By 1970, almost half of the public oil and gas producing companies were using a form of the full cost method.

1.45 Full cost accounting generally provides for capitalizing (within a cost center) all costs incurred in exploring for, acquiring, and developing oil and gas reserves—regardless of whether or not the results of specific costs are successful. This method is based on the premise that the costs of unsuccessful exploration efforts are necessary for the discovery of reserves even though such expenditures are made with the knowledge that specific efforts may not actually locate any. Thus, all costs incurred in acquiring mineral rights, in drilling, and in exploration activities—along with all carrying costs of nonproducing properties in the cost center—are treated as the cost of reserves in that center. The costs capitalized in a cost center are then amortized and charged to expense while the mineral reserves in that cost center are produced.

1.46 Under the full cost method, the cost center is used to "pool" costs to be later matched with revenues generated from the cost center's operations. Under the broadest concept, the company's entire worldwide oil and gas operations would be treated as a single cost center. Most companies, however, consider the continent or the individual country a cost center, and the SEC accounting rules specify the size of cost centers to be an individual country.

1.47 In 1969, the American Institute of Certified Public Accountants (AICPA) published Accounting Research Study (ARS) No. 11, which called for the elimination of the full cost method and recommended that the successful efforts method be the only acceptable method. The Accounting Principles Board (APB) appointed a committee to develop an authoritative opinion on financial accounting and reporting for the oil and gas industry; however, the APB was terminated in 1973 before the committee completed its charge.

1.48 In December 1977, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.* The statement required a form of successful efforts accounting as the uniform method for all enterprises engaged in oil and gas producing activities.

1.49 In summary, successful efforts accounting as specified by FASB Statement No. 19 provides that—

1. Geological and geophysical costs, costs of carrying and retaining undeveloped properties, and dry hole and bottom hole contributions should be charged to expense when incurred.

2. Acquisition costs should be capitalized initially; however, losses should be recognized if the values of unproved properties are determined to be impaired on the basis of a required periodic assessment.
3. The costs of drilling exploratory wells and exploratory-type stratigraphic test wells should be capitalized pending determination of whether the well has found proved reserves. The costs of unsuccessful exploratory wells should be charged to expense.
4. The costs of drilling development wells, including unsuccessful development wells, should be capitalized.
5. Production costs—together with the amortization of the capitalized acquisition, exploration, and development costs—should become the cost of oil and gas produced.
6. Capitalized costs are accumulated by cost centers, which provide a means whereby costs can be collected and amortized against related revenues. For amortization purposes, the cost center is the individual property or an aggregation of properties in the same field or reservoir.
7. Capitalized acquisition costs should be amortized on the unit-of-production method using total proved oil and gas reserves. Capitalized exploration and development costs should be amortized on the unit-of-production method using proved developed oil and gas reserves.

1.50 The SEC called for public hearings in August 1978 before adopting the statement as the authoritative standard of accounting and reporting for oil and gas producing companies filing reports with the SEC. Because of the strong opposition voiced at those hearings, the SEC issued Accounting Series Release (ASR) No. 253, section 406, *Adoption of Requirements for Financial Accounting and Reporting Practices for Oil and Gas Producing Activities*. This ASR—

- Adopted the form of successful efforts accounting and the disclosures prescribed by FASB Statement No. 19.
- Indicated the SEC's intention to develop a form of the full cost accounting method as an alternative acceptable for SEC reporting purposes (ASR No. 258, section 406).
- Concluded that both the full cost and successful efforts methods of accounting, based on historical costs, fail to provide sufficient information on the financial position and operating results of oil and gas producing companies and, accordingly, that steps should be taken to develop an accounting method based on a valuation of proved oil and gas reserves. (The SEC later decided that the valuation accounting it proposed—reserve recognition accounting (RRA)—was no longer considered to be a potential method of accounting in the primary financial statements of oil and gas producers. The SEC also announced its support of an undertaking by the FASB to develop a comprehensive disclosure package for those engaged in oil and gas producing activities.)
- Adopted rules that require financial statement disclosure of certain financial and operating data regardless of the method of accounting followed.

In ASR Nos. 257 and 258, section 406, the SEC released its final rules for successful efforts and full cost accounting. At that point, companies under SEC jurisdiction could follow either the full cost method prescribed in ASR No. 258, section 406.01.c., or the successful efforts method prescribed in ASR No. 253, section 406.01.b., as modified by ASR No. 257, section 406—a method identical to that contained in FASB Statement No. 19.

1.51 In response to the SEC's issuance of ASR No. 253, section 406.01.b., the FASB issued FASB Statement No. 25, *Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies*. This statement suspended, for an indefinite period of time, most of the provisions of FASB Statement No. 19. However, some provisions of FASB Statement No. 19, including deferred income taxes and some aspects of property conveyances and disclosure requirements, were retained and became effective.[1] Thus, companies that report to the SEC may follow *either* the full cost accounting method prescribed by ASR No. 258, section 406.01.c., or the successful efforts method prescribed by ASR No. 253, section 406.01.b., as modified by ASR No. 257, section 406—a method identical to that contained in FASB Statement No. 19. For nonpublic companies there is no prescribed method of accounting for costs incurred in oil and gas exploration or for amortization of those capitalized costs.

1.52 In November 1982, the FASB issued Statement No. 69, *Disclosures About Oil and Gas Producing Activities*. This statement amended FASB Statement No. 19 by establishing disclosures about oil and gas producing activities to be made for publicly traded enterprises when presenting a complete set of annual financial statements. It also requires all entities (public and nonpublic) engaged in oil and gas producing activities to disclose in their financial statements the method of accounting for costs incurred in these activities and the manner of disposing of capitalized costs relating to those activities. The SEC, in Financial Reporting Release (FRR) No. 9, *Supplemental Disclosures in Oil and Gas Producing Activities*, section 406.02, generally adopted these disclosure standards. In summary, FASB Statement No. 69 provides for the following disclosures for public companies as supplementary information:[2]

- Net quantities of proved reserves and proved developed reserves of oil (including condensate and natural gas liquids) and gas as of the beginning and end of the year, with details of changes in proved reserves during the year
- Capitalized costs relating to oil and gas producing activities and the related depreciation, depletion, amortization, and valuation allowances as of the end of the year
- Costs incurred in oil and gas property acquisition, exploration, and development activities during the year
- Details of the results of operations for oil and gas producing activities during the year
- Standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities as of the end of the year, with details of changes in the standardized measure during the year

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[1] FASB Statement No. 25 also states that for purposes of applying paragraph 16 of APB Opinion No. 20, *Accounting Changes,* successful efforts is the preferable method of accounting for oil and gas producing activities; therefore, no justification for a change to the successful efforts method is necessary—nor is a preferability letter for such a change required by the SEC for its registrants. Any change to the full cost method must be justified as being preferable in the circumstances, and a preferability letter describing those circumstances must be filed with the SEC for registrants. The SEC's position on preferability letters for accounting changes to or from the successful efforts or full cost methods is described in ASR No. 300, section 406.01.d.

[2] Supplementary information is considered to be outside the basic financial statements and is therefore not required to be audited. However, SAS No. 52, *Omnibus Statement on Auditing Standards—1987, Required Supplementary Information*, and Auditing Interpretation No. 1 of SAS No. 52, "Supplementary Oil and Gas Reserve Information," at AU section 9558.01-.06, describe the auditor's responsibility with regard to this information.

1.53 For purposes of this guide, "successful efforts" refers to the accounting method specified in FASB Statement No. 19 and "full cost" refers to the accounting method specified in Regulation S-X of the SEC. It should be recognized that hybrids of both of these methods are commonly referred to by those names and often are considered to be within the framework of generally accepted accounting principles for companies not reporting to the SEC.

1.54 In addition to accounting methods included within generally accepted accounting principles, income tax laws and regulations have a major effect on both the accounting and the economic decisions of oil and gas companies. There are many significant differences between the income tax and either of the principal accounting methods, including the ability to charge intangible drilling costs to expense for income tax purposes. The auditor should have an understanding of the more common differences, which are discussed in chapter 3.

Impairment of Long-Lived Assets

1.55 FASB Statement No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, establishes accounting standards for the impairment of long-lived assets, certain identifiable intangibles, and goodwill related to those assets to be held and used, and for long-lived assets and certain identifiable intangibles to be disposed of. The Statement requires that long-lived assets and certain identifiable intangibles to be held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability, the Statement requires that the entity estimate the future cash flows expected to result from the use of the asset and its eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, an impairment loss is recognized. Otherwise, an impairment loss is not recognized. Measurement of an impairment loss for long-lived assets and identifiable intangibles that an entity expects to hold and use should be based on the fair value of the asset.

1.56 FASB Statement No. 121 also requires that long-lived assets and certain identifiable intangibles to be disposed of be reported at the lower of carrying amount or fair value less cost to sell, except for assets covered by APB Opinion No. 30, *Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions.*

1.57 FASB Statement No. 121 (paragraph 25) also amends FASB Statement No. 19 by adding a new paragraph dealing with impairment test for proved properties and capitalized exploration and development cost after paragraph 62. The paragraph reads as follows:

Impairment Test for Proved Properties and Capitalized Exploration and Development Cost

The provisions of FASB Statement No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, are applicable to the costs of an enterprise's wells and related equipment and facilities and the costs of the related proved properties. The impairment provisions relating to unproved properties referred to in paragraphs 12, 27-29, 31(b), 33, 40, 47(g), and 47(h) of this Statement remain applicable to unproved properties.

Chapter 2

Business Activities of the Oil and Gas Producing Industry

Acquisition of Mineral Properties

2.01 In the oil and gas industry, rights to drill wells and produce minerals found are generally obtained through leasing transactions. Although the operator may acquire the fee interest in the property (outright ownership of both minerals and surface), this is not customary today. The operator usually obtains a lease from a landowner, either through an in-house landman or from an independent lease broker. The landman or broker researches the public records to verify the legal owner of the mineral interest in the property and may obtain legal title opinions, although in many instances the title work will not be performed until shortly before drilling commences. The landman or broker then negotiates the lease terms with the landowner. Leases on state-owned properties are normally awarded through a bidding process, with leases granted to the highest bidder. Leases on federally owned properties located offshore or on known geological structures, as well as certain other properties, are also awarded by bidding. Leases on most federally owned properties located onshore are awarded through lease application systems with a standard fee.

2.02 As discussed under "Exploration" in paragraphs 2.31 through 2.46, exploration activities may take place prior to acquisition of the mineral rights.

The Lease

2.03 The most important and most commonly found provisions in oil and gas leases are outlined below, but it is important that oil and gas leases be read carefully by the auditor to obtain an understanding of the principal provisions. A standard lease agreement, prepared by the American Association of Petroleum Landmen, is often adapted to fit particular circumstances. Although the basic provisions in leases are similar, each lease may contain unique provisions. These basic provisions are discussed in the following paragraphs.

2.04 *Lease Bonus.* The lease bonus is the cash or other consideration paid to the lessor by the lessee in return for the lessor's granting the lessee rights to explore for minerals, drill wells, and extract any minerals found. The bonus is computed on a per-acre basis and may range from a few dollars per acre in wildcat locations to thousands of dollars per acre for locations near producing properties. In negotiated leases, the full amount of the bonus may not be specified in the lease agreement.

2.05 *Primary Term.* The maximum period of time allowed for the lessee to commence drilling a well is referred to as the "primary term," which is normally three to ten years.

2.06 *Drilling Obligation.* The lease generally stipulates that either drilling operations begin within a specified period (usually one year) or that the lessee make a specified payment (delay rental) to the lessor. In succeeding years, the same drilling obligation exists but can be deferred (and the lease retained) by making the specified payment; however, no provision is made for the extension of the lease by payment of rent beyond the primary term.

2.07 *Delay Rentals.* The payment made to defer drilling activities for an additional year is called a delay rental. The amount of the delay rental is normally much smaller than the lease bonus.

2.08 *Royalty Provisions.* The lessor retains a royalty interest in the minerals. This interest entitles the lessor to receive free and clear of all costs a specified portion of the oil and gas produced, or a specified portion of the value of such production, except for (1) the related state severance or production taxes, (2) the windfall profit tax, and (3) certain costs necessary to get the product into a salable condition.

2.09 *Production Holds Lease.* Once a successful well has been drilled and commercial production is begun, the lease usually remains in effect for as long as there is production without extended and indefinite interruption. If production ceases, the operator must act in good faith to resume the extraction of oil or gas within a reasonable time (specified in the lease contract).

2.10 *Right to Assign Interest.* The lease contract grants each party the right to assign, without approval of the other party, any part or all of its rights and obligations.

2.11 *Fixed or Mandatory Rentals.* The contract may provide for rental payments that cannot be avoided even though the property is abandoned or drilling has begun. In effect, these payments are deferred bonuses paid on an installment basis.

2.12 *Shut-in Royalties.* Most lease contracts provide for shut-in royalties, which represent payments by the operator to the royalty owner if a successful well has been drilled but production has not begun within a specified time. Shut-ins frequently occur on properties containing gas and may be caused by the absence of a market, a lack of transportation, the necessity to obtain permission from a governmental unit, or for other reasons. Shut-in payments may or may not be recoverable by the operator out of future amounts accruing to the royalty owner.

2.13 *Offset Clause.* A common provision called an offset clause requires an operator to drill such offset wells to prevent drainage of oil or gas to another tract that a prudent operator would drill under similar circumstances.

2.14 *Compensatory Royalties.* Payments known as compensatory royalties are made by oil companies to royalty owners as compensation for the latter's loss of income during periods when the company has not fulfilled its obligation to drill.

2.15 *Guaranteed or Minimum Royalties.* If leases are acquired on property having a high probability of being productive, the mineral owner may be able to negotiate a provision in the lease requiring the lessee to guarantee the mineral owner a specified minimum royalty payment each month or each year. If the royalty owner's share of net proceeds from production is less than the specified amount, the lessee must pay the difference. Guaranteed payments may be nonrecoverable or may be recoverable out of future royalties accruing to the royalty owner.

2.16 *Surface Damage.* This provision is sometimes incorporated in a mineral lease to require a lessee to pay for any damages to the leasehold that occur from drilling or operating the lease.

Other Considerations—Acquisition

2.17 Almost all transactions related to oil and gas activities have their foundations in the lease contract.

2.18 Oil and gas producers may also acquire interests in properties that have already been leased and perhaps drilled and developed by others. This is usually accomplished by assigning all the rights and obligations of the original lessee through a sale or by acquiring the operating interest subject to a nonoperating interest retained by the original lessee (sublease). Typically, the assignment contract specifies an agreed-on value of well and lease equipment, and the balance of purchase price is deemed to be applicable to the mineral rights obtained.

2.19 When a fee interest in property is acquired, the transaction is similar to a typical real estate transaction in that the acquirer may have all the interests in a property and not just mineral interests.

2.20 After mineral rights have been acquired through purchase or lease, several years may elapse before drilling begins. Economic or market conditions may delay development. During that period, the holder of the rights may be required to pay ad valorem taxes and pay other carrying costs in addition to possible delay rentals or minimum royalty payments.

2.21 The company will usually maintain a prospect file or a lease file, or both, for each property. These files generally include, as a minimum, a copy of the lease, the survey or other legal description of the property, and the title opinions. As the prospect develops, the lease file will include additional documents such as AFEs, division orders, purchase contracts (if applicable), operating agreements, and producer-status certifications.

2.22 The lessee should keep abreast of the timing of delay rental payments and reassignment obligations. If delay rental payments are not made when due, the lease contract expires. It is important that lease rentals be paid on properties that the lessee does not wish to surrender. Customarily, the lessee may avoid all obligations and give up all rights and responsibilities by simply failing to pay rentals when due, or the lessee may terminate the contract at any other time by executing a formal lease surrender or a quit claim deed. In cases where the original lease has been assigned and an overriding royalty or other type of interest is retained, a reassignment clause may be executed. If so, the assignee would be required to notify the assignor in advance of an intent to permit the lease to lapse.

2.23 If the lessee wishes to retain a property whose primary term is about to expire but on which drilling has not yet begun, an extension of the original lease may be agreed to by both parties upon an additional payment by the lessee, or a top lease (a new lease contract on the same property) may be executed, usually involving an additional bonus payment by the lessee. A top lease may also be taken by a third party, in expectation of the expiration of the existing lease.

Accounting for Acquisition Costs

2.24 *Successful Efforts.* Under the successful efforts method, costs associated with the acquisition of leases are capitalized when incurred. These consist of costs incurred in obtaining a mineral interest in a property, such as the costs of lease bonuses and options to lease, brokers' fees, recording fees, legal costs, and other similar costs in acquiring property interests.

2.25 Unproved properties are assessed periodically to determine whether they have been impaired under successful efforts accounting. A property may be considered impaired if, for example, a dry hole has been drilled on a portion of it or in close proximity, and the company has no intention of further drilling on the property. Also, as the expiration of the lease term approaches and the company has not begun drilling on the property or nearby properties, the possibility of partial or total impairment of the property may increase. Impairment on individually significant unproved properties is assessed on a property-by-property basis. If a property is found to be impaired, an impairment allowance is provided, and a loss is recognized in the income statement.

2.26 Unproved properties whose costs are individually insignificant may be amortized in the aggregate or by groups, on the basis of the experience of the company in similar situations and with the consideration of such factors as the primary lease terms, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past.

2.27 Properties are classified as unproved until proved reserves are discovered on the property. If a property being reclassified as proved has previously been impaired on an individual basis and a valuation allowance has been established, the net amount (acquisition cost minus valuation allowance) is reclassified. If a valuation allowance has been provided on the property on a group basis, the gross acquisition cost is reclassified as proved.

2.28 If an unproved property is surrendered or expires, the cost of the property is charged against the impairment allowance to the extent it has been provided. Any excess basis is charged to loss.

2.29 *Full Cost.* Under the full cost method, all costs associated with the acquisition of properties are capitalized within the appropriate cost center. Prior to 1983, all capitalized costs were included in the full cost pool and became part of the amortizable base; however, in certain circumstances, the cost of unusually significant investments in unproved properties and major development projects could be excluded from costs to be amortized. Effective with the SEC's adoption of Release No. FRR 14, *Oil and Gas Producers—Full Cost Accounting Practices; Amendment of Rules*, section 406.01.c.i., in 1983, all costs directly associated with the acquisition and evaluation of unproved properties may be excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The computation of depreciation, depletion, and amortization (DD&A) is further discussed under "Accounting for Production" in paragraphs 2.105 through 2.119.

2.30 Full cost accounting requires that properties excluded from the amortization computation be assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant are assessed individually. When it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties may be grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized. Full cost accounting does not require the assessment of properties included in the amortization computation for impairment; rather, the cost pool in the aggregate is compared to the cost center "ceiling." (The cost ceiling is further discussed under "Accounting for Production" in paragraphs 2.105 through 2.119.) Some companies not subject to SEC regulations follow other methods of computing the cost "ceiling."

Exploration

2.31 The purpose of geological and geophysical exploration is to obtain information about subsurface geological conditions in an area that can be used in assessing the probability that oil or gas exists in commercial quantities. This involves first locating underground structures or stratigraphic variations that are conducive to the trapping of oil and gas, then carrying out detailed tests to see if drilling is justified.

Origin and Accumulation of Oil and Gas

2.32 Oil and gas are generally believed to have originated from organic matter in sedimentary rocks. Layer upon layer of sediment and animal and plant deposits were buried successively until the accumulation became thick, sometimes thousands of feet. Bacteria took oxygen from the trapped organic residues and gradually broke down the matter into substances rich in carbon and hydrogen. The weight of the overburden created high pressure and temperature, compacted and squeezed the sediment into hard shales, turned the organic material into oil and gas, and expelled the oil and gas from the shale into reservoir beds.

2.33 Oil and gas are usually not found where they were formed. Source rocks, in which the organic material was originally trapped, are fine-grained and relatively impervious. They rarely hold oil and gas in significant quantities. The oil and gas normally move from the source rock into more porous rocks, then migrate upward through the porous rocks until they reach a structural closure or an impermeable barrier caused by stratigraphic variations. These closures and barriers are called traps and are the cause for accumulation of oil and gas into a pool or field.

2.34 An oil or gas reservoir is often erroneously viewed as a large pool of liquid or gas beneath the earth, like a subterranean pond. In reality, a petroleum reservoir is porous rock capable of containing gas, oil, or water. The petroleum is accumulated in the small pore spaces of the rock. For an oil and gas pool to be formed, the following features must be present:

- There must have been an original source bed of organic material, subjected to the proper temperature and pressure over sufficient time.
- There must be a reservoir rock—a rock filled with pores so the oil or gas can collect (porosity).
- The rock's pores must be interconnected so the oil or gas can move or migrate (permeability).
- There must be a trap that will cause the oil or gas to collect in a pool and prevent it from moving further upward.

Prospecting for Oil and Gas

2.35 At one time, prospecting for oil and gas merely involved visible sightings of surface accumulations. The primary exploration technique used in many areas was surface geological mapping to define the structural features expressed in the rock outcrops that indicated an oil and gas trap would be present in the subsurface. However, these obvious drilling sites were rapidly developed and subsurface geological and geophysical studies were needed to locate petroleum reservoirs. Several scientific methods were developed, including the seismic method, the magnetic method, and the gravity method. Surface geological studies, however, are still used to locate areas structurally favorable for oil and gas accumulations in new exploration areas.

2.36 Geological exploration activities include the following: (1) studying the structural configuration of exposed formations on the surface in order to secure information about the structure of parallel subsurface beds; (2) examining the surface for oil or gas seepages, or paraffin residue that indicates past seepage of hydrocarbons; and (3) examining subsurface strata through the use of samples taken by core drilling as well as measurements of certain physical properties of the sample rocks, such as resistivity and radioactivity. In addition, geologists and other scientists make many different tests of cuttings brought to the surface in the process of drilling wells.

2.37 Some large companies maintain exploration departments or establish exploration subsidiaries that own or lease geological and geophysical equipment and employ exploration crews and scientists. Most companies, both large and small, contract with exploration and oil industry service companies to carry out their exploration.

2.38 If an outside contractor is used, the contract normally contains detailed provisions about the following: (1) the area to be covered; (2) the nature of work to be performed; (3) the time period in which the exploration is to be carried out; (4) the nature of reports to be made; and (5) rules for insuring security of data, as well as other provisions.

2.39 When the operating company maintains its own exploration department, it is customary for costs of that department to be accumulated and allocated to exploration activities and projects. The allocation is based on standardized charges, such as cost per day for a crew, costs per shot-point for seismic work, hourly basis for engineers, and the like. Frequently, employment contracts with geologists or geophysicists call for the employee to receive ownership interests in leases acquired as the result of exploration.

2.40 For control purposes, exploration is undertaken on a project basis. A "project area" is usually the maximum size that can be efficiently explored under a coordinated exploration program. A preliminary reconnaissance of the project area using magnetometers, gravitometers, aerial photography, and surface geology seeks to define "areas of interest" for oil and gas accumulations that justify more intensive exploration through seismic shooting or core drilling. The detailed exploration is conducted to determine more specific prospective areas for evaluation with drilling and may be conducted either before or after acquiring the lease.

2.41 Once the seismic data have been analyzed and the leases acquired, the company determines the exact spot for drilling. Wells drilled in an unproved area are referred to as "exploratory" wells. The more risky exploratory wells are referred to as "wildcat" wells and are often drilled in areas that have not previously yielded commercial production.

Other Considerations—Exploration

2.42 Some exploration can be conducted without direct access to privately owned land surface; for example, photography and gravimetric and magnetic measurements can be conducted from planes or satellites, and studies of surface strata can be made from creek beds or river beds and from public roads and railroads cut through hills. However, to gain access to private land the operator must secure permission from landowners. This transaction may involve a "rights to explore only" contract, which permits the operator to conduct exploration on the property but does not provide for subsequently leasing acreage. Permission may also be granted through a "rights to explore with option to acquire acreage" contract. This agreement calls for the operator to make a payment at the time the contract is signed, and it gives the operator not only the right to explore but also the right to lease all or part of the acreage by paying a specified bonus per acre within the option period (often six months).

2.43 Holders of mineral properties may make cash contributions to other operators who are drilling wells on nearby properties in exchange for which the operator conducting drilling provides the contributor with geological data, including samples from the well being drilled. Sometimes the transaction involves a "bottom hole contribution," calling for cash to be paid when the well has been drilled to a specific geological formation or to a specified depth. In other cases, the transaction involves a "dry hole contribution," which provides that the contribution is to be made only if the well being drilled does not produce commercial reserves. If the well is a producer, no contribution is made.

Accounting for Exploration Costs

2.44 Costs incurred in the geological and geophysical activities are commonly referred to as "G&G costs." G&G costs include the following: costs of topographical, geological, and geophysical studies; rights of access to properties to conduct those studies; and salaries and other expenses of geologists, geophysical crews, or others conducting those studies. Also included in exploration costs are expenses of carrying and retaining undeveloped properties, dry hole and bottom hole contributions, costs of drilling and equipping exploratory wells, and costs of drilling exploratory-type stratigraphic test wells.

2.45 *Successful Efforts.* Under the successful efforts method, G&G costs, costs of carrying and retaining undeveloped properties, and dry hole and bottom hole contributions are charged to expense as incurred. The costs of drilling exploratory and exploratory-type stratigraphic test wells are capitalized, pending determination of whether the well can produce proved reserves. If it is determined the well will not produce proved reserves, the capitalized costs, net of any salvage value, are charged to expense. See "Accounting for Drilling and Development Costs" in paragraphs 2.60 through 2.67.

2.46 *Full Cost.* Under the full cost method, all costs associated with the exploration of properties are capitalized within an appropriate cost center. These cost centers are established on a country-by-country basis. The costs become part of the full cost pool.

Drilling and Development

2.47 Although most wells drilled by oil and gas operators are intended to find oil and gas and to extract minerals, some wells are drilled solely to obtain geological information (stratigraphic test wells) or to facilitate production (gas or water injection wells). Wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive are classified as development wells; other wells drilled to find oil and gas are called exploratory wells.

2.48 Various drilling methods exist. Rotary drilling is by far the most prevalent method. Rotary drilling, as the name implies, involves the application of a rotating motion to a drill bit to bore a hole into the earth. A drilling fluid ("mud") is continually circulated in the drilled hole to flush the cuttings from the hole as it is drilled.

2.49 Although well bores are normally planned to be drilled vertically, it is sometimes necessary or advantageous to drill at an angle, especially in offshore operations. Directional drilling makes it possible to drill a number of wells using the same rig from the same surface location. Directional drilling has other applications. Wells may be drilled from the shoreline and deflected to reach a reservoir offshore. It is also used, among other things, for exploratory drilling to locate the fault plane of a structure.

The Drilling Contract

2.50 Operators may carry out drilling activities using their own rigs, or they may hire independent drilling contractors to drill wells. The terms of drilling contracts vary widely, but most involve footage-rate contracts, day-rate contracts, turnkey contracts, or a combination of the three.

2.51 Under footage-rate contracts, the drilling contractor is paid a fixed amount per foot drilled to a specified depth or a number of feet below a geological formation. The drilling contractor provides the rig, the drilling crew, and certain materials and supplies. The operator may provide drilling mud and normally provides all well equipment. In a footage-rate contract, some of the risk of drilling is shifted from the operator to the drilling contractor. If the rig is idle through no fault of the driller, a daily or hourly charge generally is specified. If the rig can only drill a few feet per day because of hard rock or other problems, the drilling contractor bears the economic adversity.

2.52 Under day-rate contracts, the operator is charged a specified sum per day for the use of a drilling rig and drilling crew, which may vary depending on whether the rig is drilling or idle, the extent of equipment furnished, or other factors. The cost of a well bore hole is a function of the speed of the rig, the depth to be drilled, the geological formation encountered, and other drilling factors. Typically, under day-rate contracts, the drilling contractor furnishes the rig and crew, but the operator provides supplies, mud, and services.

2.53 Under a turnkey contract, the contractor guarantees to the operator a hole drilled to a specified depth. The drilling contractor bears most of the risk of adversity associated with drilling costs. Turnkey contracts usually specify completing a well to a certain point—such as to casing point, to completion, to tanks, or the like. The drilling contract specifies the point or points at which payment is to be made by the operator.

2.54 Frequently, an operator will assign an economic interest in the leasehold to another party in return for the latter's assumption of the cost of drilling a well. These drilling arrangements are discussed under "Conveyances" in paragraphs 2.120 through 2.131.

Completing or Plugging and Abandoning the Well

2.55 Once the well has been drilled to total depth, the operator evaluates the evidence to determine whether the costs of completion can be justified. This is often referred to as "casing point." Completion of the well does not necessarily mean the well will be profitable. Generally, the well will be completed if the expected revenues exceed the incremental completion costs and the expected operating expenses. Therefore, even though total costs, including drilling costs, may not be recovered, completion may be economically justified. It is common in the industry—particularly in promoted ventures—for costs to be shared in different percentages depending on whether they are incurred before casing point or after casing point. The determination of this cut-off point can be very important in the allocation.

2.56 In completing the well, casing is set and cemented into the hole, which seals off the producing formation. The most widely used method of completion is to perforate the casing with explosive charges that puncture through the casing and cement into the formation so the oil and gas can enter the well bore. Depending on the permeability of the formation, it may also be necessary to fracture or acidize the formation to obtain the desired flow of oil and gas. These are specialized services, generally performed by independent well service companies.

2.57 Completion of the well also involves the installation of equipment. The specific equipment required will depend on the nature of the well, whether oil or gas or both are produced, the availability of pipelines, and other factors.

Developing the Reservoir

2.58 Normally, a single well is not sufficient to complete the development of a reservoir. Additional wells usually increase the ultimate quantity of oil or gas to be extracted from the reservoir. They also affect the timing of the extraction and thus the present value of the income stream. While the presence of an oil and gas reservoir was established through the drilling of the discovery well, the property may or may not have sufficient potential reserves to warrant the further expenditures required for the complete development. Core samples, along with pressure tests, flow tests and rates, fluid analyses, and other geological data, are used in deciding whether to continue with development. Assuming that a successful discovery well has been drilled, drilling and development will continue until the boundaries of the reservoir are delineated.

The Regulatory Environment

2.59 Various state agencies issue regulations concerning well spacing limitations, rules regarding unitization of reservoirs, and allowable maximum production limits. Normally, the operator must obtain permits before exploration or drilling commences. Reports on well depths and results of drilling activities must be filed with the applicable agency. For example, if a well is determined to be dry or commercially unproductive, a plugging report is filed with the state agency. If a well is completed, various types of information, including production, must be filed on a regular basis with the appropriate state and federal agencies, including the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the Minerals Management Service.

Accounting for Drilling and Development Costs

2.60 *Successful Efforts.* Under the successful efforts method, all costs incurred while drilling an exploratory well are capitalized pending determination of whether the well has found proved reserves. If the well has not found proved reserves, the capitalized costs of drilling the well, net of any salvage value, are charged to expense. If an exploratory well or exploratory-type stratigraphic test well is in progress at the end of a period and the well is determined not to have found proved reserves before the financial statements for that period are issued, the costs incurred through the end of the period, net of any salvage value, are charged to expense for that period (FASB Interpretation No. 36, *Accounting for Exploratory Wells in Progress at the End of a Period).*

2.61 All drilling and completion costs that directly lead to the extraction and production of oil and gas reserves and all development dry holes are capitalized. Capitalized costs are accumulated by cost centers, which provide a means whereby costs can be collected and amortized against the revenues therefrom. For amortization purposes, the cost center is the individual property or an aggregation of properties in the same field or reservoir.

2.62 Because development dry holes are capitalized and exploratory dry holes are expensed, the distinction between them is extremely important and should be made by the company prior to drilling.

2.63 *Full Cost.* A company that employs the full cost method of accounting capitalizes all costs associated with the drilling and completion of a well, regardless of whether or not it results in the discovery of oil and gas reserves.

2.64 *Interest Capitalization.* Interest capitalization may be accounted for quite differently under the full cost and successful efforts methods. A significant difference may occur between these two methods when a company following the full cost method does not elect to exclude costs of unevaluated properties from costs to be amortized.

2.65 FASB Interpretation No. 33, *Applying FASB Statement No. 34 to Oil and Gas Producing Operations Accounted for by the Full Cost Method,* states that assets whose costs are being currently depreciated, depleted, or amortized are assets in use in the earnings activities of the enterprise and are not assets qualifying for capitalization of interest.

2.66 Under the successful efforts method, capitalized costs of each property represent the company's assets. When a property is ready for production to commence, the capitalized costs of that property are considered "in the earnings activities of the enterprise," and are no longer qualifying assets. Costs of successful and unsuccessful exploratory efforts, including related leasehold costs, incurred on a property are qualifying assets until the property is ready for production to commence.

2.67 Under both methods, capitalized interest is attached to the qualifying costs on which the interest was computed and amortized in the same manner as those costs.

Oil and Gas Reserves

2.68 The discovery of oil and gas reserves is the primary objective of exploration and development activities. In order to assure its long-term existence, an oil and gas producing company must continue to replace the reserves produced with newly discovered reserves.

2.69 Reserve determinations have a significant effect on a company's results of operations and financial position. For a company following the successful efforts method of accounting, exploratory wells discovering proved oil and gas reserves will be capitalized instead of being expensed. Additionally, for both the successful efforts and full cost methods of accounting, amortization of capitalized costs is computed by means of the unit-of-production method, based on proved reserves. Further, under the full cost method, there is a limitation on capitalized costs in each cost center based primarily on a calculation of future net revenues from estimated production of proved oil and gas reserves.

2.70 Reserves are classified as either proved or potential (potential reserves can be further categorized as probable and possible). Only proved reserves are used for accounting purposes.

Proved Reserves

2.71 Proved oil and gas reserves (as defined by the FASB and the SEC) are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under *existing economic and operating conditions* (prices and costs as of the date the estimate is made). Prices include consideration of fixed and determinable changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

2.72 Reservoirs are considered proved if economic producibility is supported by either actual production or a conclusive formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil or oil-water contacts or both, if any, and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

2.73 Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provide support for the engineering analysis on which the project or program was based.

2.74 *Proved Developed Reserves.* Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed, through production response, that increased recovery will be achieved.

2.75 *Proved Undeveloped Reserves.* Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

2.76 *Subdivisions.* Although variations in terminology occur depending on the engineer responsible for the study, it is quite common to find reserve classifications further divided as follows:

- *Producing reserves*—Those reserves estimated to be recoverable from zones currently open and producing.
- *Shut-in reserves*—Those reserves estimated to be recovered from zones in which completions have been made in wells ready to produce and awaiting connection to delivery facilities.
- *Behind-pipe reserves*—Those reserves behind casing in producing wells.

Potential Reserves

2.77 Proved reserves have industry and regulatory definitions, but there are no such standards for potential reserves, which are often referred to as probable and possible. These reserve classifications are not subject to SEC disclosure. However, since potential reserves are commonly used terms in the industry, these definitions are offered as examples.

2.78 *Probable Reserves.* Probable reserves are those that are supported by favorable engineering and geological data but are subject to some element of risk, which prevents classification as proved reserves.

2.79 *Possible Reserves.* Possible reserves include speculative reserves where risk is relatively high. Usually, reserves to be included as possible are those that depend on some favorable development or event (such as creation of a unit to conduct fluid-injection operations or remedial work to correct a mechanical defect) that is not predictable with sufficient accuracy.

Definitional Problems

2.80 As indicated by the foregoing definitions, the classification of reserves is highly complex. Although the definition of proved reserves cited is from SEC regulations, it was derived directly from similar definitions developed by the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers. The definition of probable and possible reserves can vary significantly from one engineer to another.

Determination of Reserves

2.81 Reserve estimates are prepared by persons such as petroleum reservoir engineers and geologists with the specialized knowledge and experience required to estimate oil and gas reserves. The engineers may be either employees of the company or independent reservoir engineers. Reserve studies may also be prepared using various assumptions, each for different purposes.

2.82 Reserve estimates or studies are used for a variety of purposes, including—

- A basis for financing or investment decisions.
- A basis for management's estimates of internally generated cash flow and as input for better operational decisions.
- A basis for computing the depreciation, depletion, and amortization rates used in the systematic allocation of capitalized costs to the production function.
- Disclosure information about a producing company's resources, which is used in financial reporting to lenders, investors, analysts, and the SEC.
- A basis for determining cost ceiling limitations.

2.83 The initial evaluation of a well or wells is made to determine whether sufficient reserves have been discovered to justify developing the property. This evaluation is usually prepared by employees of the company based on log and core data, drill stem tests, and other available information.

2.84 Oil and gas companies should revise reserve estimates whenever there is an indication of the need for revision, at least annually. The reserve estimates prepared for this purpose are usually made as of the company's year-end. In many cases the estimate is prepared by independent reservoir engineers.

2.85 *Preparation of Estimates.* The Society of Petroleum Engineers has adopted standards pertaining to the estimating and auditing of oil and gas reserve information by qualified engineers and geologists.[3] A general understanding of the methods of, and limitations on, estimating proved reserves may be helpful to the auditor.

2.86 The following information may be used to develop reserve quantity information:

- Area and thickness of the productive zone
- Porosity of the reservoir rock
- Permeability of the reservoir rock to fluids
- Oil, gas, and water saturation
- Physical characteristics of oil and gas
- Depth to the producing formation
- Reservoir pressure and temperature
- Production history of the reservoir
- Ownership of the oil and gas property

2.87 Estimates of the reserve quantities that are economically recoverable also include consideration of estimated selling prices as well as development and production costs. The methods used to estimate recoverable reserves vary with the amount and nature of the above information that is available. After a discovery, volumetric calculations are frequently used to estimate the volume of oil and gas in-place. The in-place volume is then converted into recoverable reserves by use of an estimated recovery factor. This factor is initially based on experience in the area and the type of reservoir drive. As production data become available, it is possible to estimate reserves from reservoir performance as well as from volumetric calculations. The methods used for these combination-type procedures include material-balance calculations, decline curves, and rate cumulative curves.

2.88 *Precision of Estimates.* According to the Society of Petroleum Engineers, the reliability of reserve information is considerably affected by several factors. Initially, it should be noted that reserve information is imprecise because of the inherent uncertainties in, and the limited nature of, the data base upon which the estimating of reserve information is predicated. Moreover, the methods and data used in estimating reserve information are necessarily often indirect or analogical in character rather than direct or deductive. Furthermore, the persons estimating reserve information are required, in applying generally accepted petroleum engineering and evaluation principles, to make numerous judgments based solely on their educational background, their professional training, and their professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserve information inherently imprecise.

2.89 *Reports.* The reserve estimation process culminates in the preparation of a reserve report or reserve study. The cover letter to a reserve report should indicate the level of responsibility assumed by the estimator. For example, some reports are based solely on information obtained from the client, without corroboration. Others are prepared based on an independent review of relevant data. The degree of responsibility assumed by the estimator may affect

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[3] Society of Petroleum Engineers of American Institute of Mining Engineers, *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information* (Dallas: Society of Petroleum Engineers of AIME, 1980). See Appendix B.

the extent to which the auditor can rely on the report. Generally, the study will contain a page for each reserve classification of each well. Summary pages are included for each reserve classification of each lease or field, and there usually is a summary page for the company total by each reserve classification. Each well page normally identifies the location, the operator, and the revenue and working interest attributable to the estimated interest. Paragraphs 2.96 and 2.97 are illustrations of a summary reserve report and a reserve report for an individual well.

2.90 The reserve study may present both net unrecovered reserve volume amounts and associated cash flow from production by year. Dollar values are generally attributed only to the subject producer's interest in projected annual production. Amounts presented for each remaining year of a property's economic life are—

- Production of gas and oil, unit prices, and gross revenues. Production prices are based on current prices, which include consideration of changes in existing prices provided by law, regulatory agencies, or contractual arrangements.
- Production expenses, including production taxes, operating expenses, windfall profit tax, and equipment and development costs. Production expenses generally do not include provisions for depletion, depreciation, or amortization. Further, reserve studies assume consumption of equipment during a property's producing life and do not ordinarily consider residual values of equipment or reclamation costs.
- Future net income (revenues less production expenses) or cash flow.
- Discounted (present) value of cash flow, generally computed at various rates.

Production

2.91 After the well is completed, the production phase begins. In the case of gas wells, the pressure in the reservoir is usually sufficient so that the gas expands into the well bore when the well is opened and flows to the surface. Oil wells, however, may be flowing wells, or they may require mechanical equipment that provides artificial lift to raise the oil to the surface.

2.92 However the product is lifted from the well, fluids produced are directed to a central gathering point, often a tank battery. Some fields may be equipped with lease automatic custody transfer (LACT) units that automatically perform the following tasks: (1) measure the oil's temperature, gravity, and volume; (2) drain off basic sediment and water (BS&W); and (3) run the oil from the tank into the pipeline. The well area normally has all the equipment necessary to field-separate oil, gas, and water, as well as having adequate storage for the oil from the time it is produced until it is sold. Oil generally contains a certain amount of gas in solution, and usually some provision must be made to separate the gas from the oil before placing the oil in the storage tanks. The well fluids enter the oil and gas separator near the center, and the gas is removed from the top while the liquid (oil or water) is removed from the bottom.

2.93 At this point, the liquid is likely to contain a certain amount of water, which must be removed before the oil can be sold. For this purpose, it may be necessary to heat the liquid by passing it through a continuous type of heater. Generally, this is done in a "heater-treater," which heats the oil and water mixture, separating the water from the oil in a single operation.

2.94 The tanks in the tank battery that are used to store the oil vary in number and size, depending on the production of the lease and the frequency of the oil runs. Each tank has a strapping table that converts the feet and inches measurement of oil in the tank to barrels of oil. There is a drain at the bottom of the tank for draining the BS&W.

2.95 When the tank is full or at another predetermined time, the oil is "run," or delivered to a pipeline, tank car, or tank truck. The pipeline outlet valve on the tank is sealed with a metal seal while the tank is being filled from the well and is locked open when the tank is being emptied. This assures the pipeline company and the producer that only oil in a particular tank is entering the pipeline company's lines.

Exhibit
2.96

Example of Summary Reserve Report
Estimated Future Reserves and Income Attributable to Certain Leasehold Interests Constant Prices and Costs as of January 1, 1984

GRAND SUMMARY

TOTAL PROVED RESERVES

PROVED
ALL TYPES

	EXPENSE INTEREST	*REVENUE INTERESTS* Oil Condensate	*REVENUE INTERESTS* Plant Products	*REVENUE INTERESTS* Gas	*PRODUCT PRICES* Oil Cond $/bbl	*PRODUCT PRICES* Ptl Prod $/bbl	*PRODUCT PRICES* Gas $/MCF	*DISCOUNTED FUTURE NET INCOME-$ COMPOUNDED MONTHLY*
Initial	—							10.00% — 196,665,188
Final	—							12.00% — 179,359,985
Remarks	—							15.00% — 158,182,696
								20.00% — 131,721,903
								25.00% — 112,465,343

		ESTIMATED 8/8 THS PRODUCTION			*COMPANY NET PRODUCTION*			*AVERAGE PRICES*	
Period	*Number of Wells*	*Oil Cond Barrels*	*Plant Products Barrels*	*Gas MMCF*	*Oil Cond Barrel*	*Plant Products Barrels*	*Gas MMCF*	*Oil Cond $/bbl*	*Gas $/MCF*
1984	2014	4,495,278	0	78,972	582,266	0	9,148.881	29.20	3.65
1985	1982	4,011,947	0	81,588	627,640	0	10,428.820	29.04	3.55
1986	1953	3,327,238	0	70,871	544,532	0	10,267.884	29.09	3.58
1987	1916	2,693,302	0	59,024	459,430	0	9,216.576	29.09	3.58
1988	1853	2,210,457	0	49,712	363,511	0	8,192.621	29.06	3.57
1989	1769	1,807,246	0	41,757	327,779	0	7,162.055	29.04	3.57
1990	1696	1,509,062	0	34,712	268,341	0	6,080.123	29.08	3.57
1991	1591	1,263,449	0	29,471	227,977	0	5,274.456	29.10	3.56
1992	1492	1,080,703	0	24,969	197,970	0	4,611.570	29.02	3.55
1993	1417	892,725	0	21,434	164,874	0	4,113.842	28.98	3.55
1994	1319	769,376	0	18,166	141,628	0	3,649.656	28.96	3.54
1995	1233	678,024	0	16,395	117,695	0	3,396.624	28.94	3.53
1996	1158	635,820	0	14,359	106,398	0	3,089.405	28.94	3.52
1997	1089	538,600	0	12,294	92,873	0	2,712.902	28.95	3.53
1998	1027	457,916	0	11,113	77,163	0	2,433.164	28.91	3.53
Sub-Total		26,371,143	0	564,837	4,320,077	0	89,778.579	29.07	3.57
Remainder		3,085,260	0	79,135	476,246	0	20,678.415	29.11	3.47
Total Future		29,456,403	0	643,972	4,796,323	0	110,456.994	29.07	3.55
Cumulative									
Ultimate									

Period	COMPANY FUTURE GROSS REVENUE (FGR)-$ From Oil Cond	From Plant Products	From Gas	Total	PRODUCTION TAXES-$	WINDFALL TAX-$	EST. WINDFALL TAX REBATE-$	FGR AFTER PROD & WINDFALL TAXES-$
1984	17,001,635	0	33,361,689	50,363,324	2,456,768	1,078,278	26,915	46,855,193
1985	18,221,208	0	36,977,740	55,198,948	2,768,346	1,076,066	2,770	51,357,306
1986	15,836,372	0	36,795,471	52,631,843	2,737,504	928,175	2,433	48,968,597
1987	13,363,956	0	33,005,822	46,369,778	2,409,341	764,977	3,867	43,199,327
1988	11,143,289	0	29,226,717	40,370,006	2,075,019	664,228	1,582	37,632,341
1989	9,517,618	0	25,579,552	35,097,170	1,771,342	588,258	1,560	32,739,130
1990	7,802,682	0	21,682,704	29,485,386	1,448,139	510,547	5,049	27,531,749
1991	6,632,018	0	18,757,201	25,389,219	1,215,668	358,065	1,588	23,817,074
1992	5,744,786	0	16,382,827	22,127,613	1,033,850	180,910	486	20,913,339
1993	4,776,418	0	14,592,256	19,368,674	865,891	30,791	164	18,472,156
1994	4,100,591	0	12,932,385	17,032,976	751,322	0	0	16,281,654
1995	3,405,720	0	11,997,215	15,402,935	662,428	0	0	14,740,507
1996	3,078,639	0	10,868,148	13,946,787	582,344	0	0	13,364,443
1997	2,687,861	0	9,565,807	12,253,668	501,578	0	0	11,752,090
1998	2,230,552	0	8,596,833	10,827,385	436,412	0	0	10,390,973
Sub-Total	125,543,345	0	320,322,367	445,865,712	21,715,952	6,180,295	46,414	418,015,879
Remainder	13,858,725	0	71,747,469	85,606,194	3,031,788	0	0	82,574,406
Total Future	139,402,070	0	392,069,836	531,471,906	24,747,740	6,180,295	46,414	500,590,285

Period	DEDUCTIONS-$ Operating Costs	Ad Valorem Taxes	Development Costs	Other	Total	FUTURE NET INCOME BEFORE INCOME TAXES-$ Undiscounted Annual	Undiscounted Cumulative	Discounted 10.00%
1984	5,885,172	766,990	9,560,992	0	16,213,154	30,642,039	30,642,039	29,153,660
1985	6,059,098	864,761	7,053,377	0	13,977,236	37,380,070	68,022,109	32,193,317
1986	5,861,035	889,130	12,002,060	0	18,752,225	30,216,372	98,238,481	23,556,909
1987	5,673,339	835,283	4,715,369	0	11,223,991	31,975,336	130,213,817	22,565,372
1988	5,422,778	754,526	2,591,743	0	8,769,047	28,863,294	159,077,111	18,438,372
1989	5,194,745	658,906	1,583,459	0	7,437,110	25,302,020	184,379,131	14,631,290
1990	4,724,170	542,960	37,736	0	5,304,866	22,226,883	206,606,014	11,634,757
1991	4,386,834	465,020	24,426	0	4,876,280	18,940,794	225,546,808	8,974,851
1992	4,027,972	403,516	68,401	0	4,499,889	16,413,450	241,960,258	7,040,110
1993	3,671,220	359,110	47,781	0	4,078,111	14,394,045	256,354,303	5,588,724
1994	3,356,491	317,181	25,425	0	3,699,097	12,582,557	268,936,860	4,422,315
1995	2,963,873	271,998	149,584	0	3,385,455	11,355,052	280,291,912	3,612,591
1996	2,648,008	249,626	73,939	0	2,971,573	10,392,870	290,684,782	2,993,075
1997	2,391,720	220,060	50,000	0	2,661,780	9,090,310	299,775,092	2,369,793
1998	2,150,402	192,757	11,245	0	2,354,404	8,036,569	307,811,661	1,896,515
Sub-Total	64,416,857	7,791,824	37,995,537	0	110,204,218	307,811,661		189,071,651
Remainder	23,424,892	1,275,444	493,755	0	25,194,091	57,380,315	365,191,976	7,593,537
Total Future	87,841,749	9,067,268	38,489,292	0	135,398,309	365,191,976		196,665,188

Exhibit 2.97

Example of Reserve Report of Individual Well

Estimated Future Reserves and Income Attributable to Certain Leasehold Interests Constant Prices and Costs as of January 1, 1984

FIELD, DESOTO PARISH, LOUISIANA
OPERATOR
WELL NO. 5

GAS LEASE
PROVED
PRODUCING

	EXPENSE INTEREST	REVENUE INTERESTS Oil Condensate	Plant Products	Gas	PRODUCT PRICES Oil Cond $/bbl	Ptl Prod $/bbl	Gas $/MCF	DISCOUNTED FUTURE NET INCOME-$ COMPOUNDED MONTHLY
Initial —	0.361950	0.271462		0.271462	30.00 (T3)		2.78 (103A)	10.00% — 138,567
Final —	0.361950	0.271462		0.271462	30.00 (T3)		2.78 (103A)	12.00% — 132,815
Remarks —	IDENTITY							15.00% — 124,945
								20.00% — 113,536
								25.00% — 103,879

Period	Number of Wells	ESTIMATED 8/8 THS PRODUCTION Oil Cond Barrels	Plant Products Barrels	Gas MMCF	COMPANY NET PRODUCTION Oil Cond Barrel	Plant Products Barrels	Gas MMCF	AVERAGE PRICES Oil Cond $/bbl	Gas $/MCF
1984	1	178	0	71	48	0	19.371	30.01	2.78
1985	1	136	0	55	37	0	14.720	30.00	2.78
1986	1	103	0	41	28	0	11.187	30.01	2.78
1987	1	78	0	31	21	0	8.500	30.01	2.78
1988	1	60	0	24	17	0	6.460	30.04	2.78
1989	1	45	0	18	12	0	4.909	30.00	2.78
1990	1	34	0	14	9	0	3.731	30.05	2.78
1991	1	26	0	10	7	0	2.835	30.05	2.78
1992	1	18	0	7	5	0	1.853	29.96	2.78
1993		0	0	0	0	0	.000	.00	.00
1994		0	0	0	0	0	.000	.00	.00
1995		0	0	0	0	0	.000	.00	.00
1996		0	0	0	0	0	.000	.00	.00
1997		0	0	0	0	0	.000	.00	.00
1998		0	0	0	0	0	.000	.00	.00
Sub-Total		678	0	271	184	0	73.566	30.01	2.78
Remainder		0	0	0	0	0	.000	.00	.00
Total Future		678	0	271	184	0	73.566	30.01	2.78
Cumulative		1,152	0	494					
Ultimate		1,830	0	765					

Period	COMPANY FUTURE GROSS REVENUE (FGR)-$ From Oil Cond	From Plant Products	From Gas	Total	PRODUCTION TAXES-$	WINDFALL TAX-$	EST. WINDFALL TAX REBATE-$	FGR AFTER PROD & WINDFALL TAXES-$
1984	1,453	0	53,851	55,304	1,538	43	0	53,723
1985	1,104	0	40,922	42,026	1,168	26	0	40,832
1986	839	0	31,100	31,939	888	13	0	31,038
1987	638	0	23,630	24,268	675	8	0	23,585
1988	485	0	17,959	18,444	513	5	0	17,926
1989	368	0	13,647	14,015	390	3	0	13,622
1990	280	0	10,372	10,652	296	2	0	10,354
1991	213	0	7,881	8,094	225	1	0	7,868
1992	139	0	5,151	5,290	147	0	0	5,143
1993	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0
1998	0	0	0	0	0	0	0	0
Sub-Total	5,519	0	204,513	210,032	5,840	101	0	204,091
Remainder	0	0	0	0	0	0	0	0
Total Future	5,519	0	204,513	210,032	5,840	101	0	204,091

Period	DEDUCTIONS-$ Operating Costs	Ad Valorem Taxes	Development Costs	Other	Total	FUTURE NET INCOME BEFORE INCOME TAXES-$ Undiscounted Annual	Undiscounted Cumulative	Discounted 10.00%
1984	3,275	0	0	0	3,275	50,448	50,448	47,998
1985	3,275	0	0	0	3,275	37,557	88,005	32,346
1986	3,275	0	0	0	3,275	27,763	115,768	21,644
1987	3,275	0	0	0	3,275	20,310	136,078	14,333
1988	3,275	0	0	0	3,275	14,651	150,729	9,359
1989	3,275	0	0	0	3,275	10,357	161,076	5,983
1990	3,275	0	0	0	3,265	7,079	168,155	3,706
1991	3,275	0	0	0	3,275	4,593	172,748	2,176
1992	2,761	0	0	0	2,761	2,382	175,130	1,022
1993	0	0	0	0	0	0	175,130	0
1994	0	0	0	0	0	0	175,130	0
1995	0	0	0	0	0	0	175,130	0
1996	0	0	0	0	0	0	175,130	0
1997	0	0	0	0	0	0	175,130	0
1998	0	0	0	0	0	0	175,130	0
Sub-Total	28,961	0	0	0	28,961	175,130		138,567
Remainder	0	0	0	0	0	0	175,130	
Total Future	28,961	0	0	0	28,961	175,130		138,567

2.98 The oil delivered is measured by gauging the height of oil in the tank before and after delivery. The oil is also tested at this time to determine its gravity or density, its temperature, and its BS&W content. Crude oil prices are posted at a standard base temperature of sixty degrees Fahrenheit, and the value of the crude oil varies with its density. Therefore, these measurements, which are made when measuring the tank's contents, are recorded on the run ticket and are used in converting to net barrels delivered. It is the responsibility of the lease operator to watch the gauging and testing of the oil done by the gauger and to be sure that the measurements are correct.

2.99 When gas is produced, it may be run directly into the gas pipeline after being measured by an "orifice meter." If the gas contains liquid condensates, it may be run through a processing facility to remove the liquids, which are similar to crude oil, before the gas is turned into the pipeline.

2.100 When an outsider purchases oil or gas, settlement is usually made monthly. The purchaser customarily withholds and remits to the state the production or severance taxes on all production. Production taxes or severance taxes may be based on the quantity of production, on the value of production, or on a combination of quantity and value. The "first purchaser" is normally required to withhold and remit to the federal government the windfall profit taxes on oil production. However, in cases where the operator is an integrated producer and in certain other cases, the operator may withhold and remit the windfall profit tax on oil.

Work-Overs

2.101 Occasionally, it is necessary to "work over" a well. Work-overs are remedial operations sometimes required to maintain maximum oil producing rates. For example, when a well begins to produce an excessive amount of salt water, a work-over rig—very similar to a drilling rig but somewhat smaller—is moved onto the well, and remedial operations are conducted.

2.102 As another example, where there is more than one producing interval in the well bore and a lower zone has been depleted, a plug-back to a higher zone is in order. The plug-back can be accomplished with a cement plug in the casing or with a bridge plug—a mechanical device that can be set in the casing to effectively seal off the casing below the point at which it is set.

Improved Recovery Methods

2.103 More than half of the oil originally in place in a reservoir may remain in the reservoir after the cessation of primary operations. To plan operations for maximum economic recovery, usually all wells are tested at regular intervals. Oil wells are tested for the oil producing rate, the gas/oil ratio, the gravity, the saltwater production, and the BS&W. Gas wells are tested to determine their gas producing rates (open-flow potential), the gas/liquid ratios, and the BTU (energy) content. When production rates from primary recovery methods are no longer satisfactory, secondary and enhanced oil recovery, or tertiary, techniques may be used to attain maximum production of the reserves.

Abandonment of Wells and Facilities

2.104 When oil and gas reserves are depleted or when production drops to the point that it is no longer economically feasible to produce, equipment is removed and operations are abandoned. Federal and state regulations and contractual obligations require that wells be plugged, all facilities and equipment removed, and the terrain restored to specified conditions.

Accounting for Production

2.105 Revenues, production costs and expenses, and income taxes are treated in the same manner under full cost and successful efforts accounting, except for DD&A and impairment costs.

2.106 *Revenue.* Most companies recognize revenue from oil produced at the point of sale—that is, when the oil is run from the tanks. Gas is not stored on the lease; thus, revenue is recognized at the point of production and sale because they are the same. However, some companies record revenue on a cash basis throughout the year, which will require an accrual adjustment at the end of the period under generally accepted accounting principles.

2.107 The company may record the revenue based on the remittance advice received from the purchaser. Generally, proceeds from production are received one to three months after the actual production has occurred. Thus, it may be necessary to estimate revenue, based on prior months' production and current lease operations (for example, whether the well has been shut in for a work-over or maintenance), in order to prepare financial statements on a timely basis.

2.108 *Inventory.* Oil in the lease tanks at the end of the accounting period is usually ignored for financial reporting purposes and inventory is not recorded because the amount of such oil normally is immaterial to the financial statements.

2.109 When inventory of oil in lease tanks is recorded, valuation methods vary in practice from an allocation of production costs and DD&A to valuations based on market price.

2.110 *Operating Expenses.* Lease operating expenses are charged to expense; examples are pumpers' wages, fuel or electricity for operating pumping equipment, subsurface maintenance, surface maintenance (such as lease roads and cutting of grass), insurance, ad valorem taxes, producing-well overhead, salt water disposal, fracturing, acidizing, and work-overs to maintain production. One exception to this occurs when a completion is made to a new zone, in which case that portion of the charges allocable to the completion may be accounted for as development or exploratory costs.

2.111 *DD&A—Successful Efforts.* DD&A of capitalized costs is recorded as the reservoir is produced and depleted. Under successful efforts accounting, DD&A is based on the unit-of-production method for the following: (1) *acquisition* costs of proved properties on the basis of total estimated units of proved (both developed and undeveloped) reserves and (2) all other costs on the basis of total estimated units of proved *developed* reserves. DD&A is computed using current-period production divided by beginning reserves (that is, reserves at the end of the period plus current-period production) either on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structure or stratigraphic condition, such as a reservoir or field.

2.112 If "significant" development costs (such as an off-shore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, it is appropriate to exclude a portion of those development costs in determining the DD&A rate until the additional development wells have been drilled. Similarly, the proved developed reserves that will be produced only after "significant" additional development costs are incurred (as in improved recovery) are excluded in computing the DD&A rate. Future development costs are not considered when computing the DD&A rate under successful efforts accounting, although estimated dismantlement, restoration, and abandonment costs net of salvage value should be considered.

2.113 When a property contains both oil and gas reserves, the units of oil and gas used to compute amortization are converted to a common unit of measure on the basis of their relative energy content (see "DD&A—Full Cost" in paragraph 2.115) *unless* (1) the relative proportion of gas to oil is expected to continue throughout the life of the property, in which case DD&A may be computed on the basis of one of the two minerals only or *unless* (2) oil or gas clearly dominates both the reserves and current production, the DD&A rate may be computed on the basis of the dominant mineral only.

2.114 The issue of whether to provide for impairment of proved properties based on the amount expected to be recoverable is unsettled under generally accepted accounting principles. Similarly, when impairment is recognized, there is considerable variation in practice in valuing the amount recoverable and in determining the property unit to which the valuation test is applied.

2.115 *DD&A—Full Cost.* Full cost companies compute their DD&A of the full cost pool on a cost center basis using the depletion rate calculated on the unit-of-production method. The DD&A rate is computed on the basis of physical units, unless economic circumstances (related to the effects of regulated prices) indicate that use of the units-of-revenue method is a more appropriate basis of computing DD&A. If physical units are used in the computation, the oil and gas must be converted to a common unit of measure on the basis of their approximate relative energy content (generally, a ratio of six thousand cubic feet (mcf, or thousand cubic feet) of gas to one barrel of oil is used); also, the current-period production is divided by reserves at the beginning of the period (that is, reserves at the end of the period plus current-period production). If the units-of-revenue method is used, the DD&A rate is computed on the basis of current gross revenues divided by the sum of the following: (1) future gross revenues based on current prices (unless fixed and determinable changes in existing prices are provided by contract) from proved reserves and (2) current-period gross revenues. This DD&A rate is multiplied by the sum of (1) unamortized costs in the pool plus (2) estimated future expenditures based on current costs to be incurred in developing proved reserves (specified in the reserve report) plus (3) estimated dismantlement and abandonment costs net of salvage value. Under certain circumstances prior to 1983, the cost of unusually significant investments in unproved properties and major development projects could be excluded from capitalized costs to be amortized. In September 1983, the SEC adopted Release No. FRR 14, section 406.01.c.i., which provided that the cost of all investments in unproved properties and major development projects expected to entail significant costs could be excluded from capitalized costs to be amortized, subject to the following conditions:

- The properties are to be assessed at least annually for impairment.
- Dry hole costs are included in the amortization base immediately.
- G&G costs that cannot be directly associated with specific unevaluated properties are to be included in the amortization base as incurred.

2.116 *Full Cost Ceiling.* A full cost company also determines if the value of proved reserves and other mineral assets in the cost center are adequate to recover the unamortized costs in the full cost pool. This test, referred to as the full cost ceiling test, is to be computed for each full cost center. Specifically, under SEC requirements as discussed in Rule 4-10(i)(4) of Regulation S-X, the net unamortized costs less related deferred income taxes should not exceed the following: (a) the present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; *plus* (b) the cost of unproved properties and major development projects not being amortized *plus* (c) the lower of cost or estimated fair value of unproved properties included in costs being amortized *less* (d) the income tax effects on the differences between the amount computed above and the tax basis of the properties involved. Any excess is charged to expense and separately disclosed during the year in which the excess occurs. Even if the cost ceiling subsequently increases, the write-off is not reinstated. However, events occurring subsequent to year-end can be considered in determining a write-down. For example, if additional reserves become proved on properties owned at year-end or price increases become known that were not fixed and determinable as of year-end, the resulting increases in present value can be considered in computing the cost ceiling.

2.117 It should be recognized that some companies not subject to SEC requirements follow other methods of computing the cost ceiling.

2.118 *Abandonments.* Under the successful efforts method, no gain or loss is recognized normally if only an individual well or a single item of equipment is abandoned as long as the well is part of a group of proved properties constituting an amortization base and the remaining properties continue to produce. The asset abandoned or retired is presumed to be fully amortized, and its cost is charged against the accumulated DD&A. Only when the last well or property ceases to produce and the entire property is abandoned does gain or loss become recognized. However, if a catastrophic event or other major abnormality results in partial abandonment or retirement of a proved property or wells or related facilities, a loss is recognized at the time of abandonment or retirement.

2.119 Under full cost accounting, abandonment or retirement of proved properties, wells, and related facilities does not result in any gain or loss being recognized.

Conveyances

2.120 The oil and gas industry is capital-intensive and usually associated with considerable risks. These characteristics, along with the wasting, nonregenerative nature of its most significant asset, require companies to continually expand their exploration efforts and capital commitments. Oil and gas companies desiring to spread the risks and to generate the funds necessary to explore and develop properties will often convey an economic interest in a property to another party in return for financing or other considerations. A conveyance is the assignment or transfer of mineral rights, usually a portion of the working interest, to another entity. A conveyance may involve a transfer of all or part of the rights and responsibilities of developing and operating a property.

Forms of Conveyances

2.121 Several types of economic interests are commonly associated with oil and gas properties. The "mineral interest" is the ownership of the right to explore for and produce the minerals underlying the surface of a property. An owner of the mineral interest would not necessarily own the surface rights. Most leasing transactions involve the lease of operating rights of the mineral interest to an oil company with the lessor retaining a royalty interest.

2.122 The working interest normally operates the property, paying most of the costs of exploration, development, and production. The working interest is also normally entitled to all the revenues generated by the property, net of any royalties or overriding royalties. The working interest can also assign a portion of its interest, thereby creating a joint working interest. This allows the original working interest to spread its risk and share the costs incurred.

2.123 Often, the working interest owner will carve out and convey to another entity a nonoperating interest. This interest may be an "overriding royalty interest," which is similar to a royalty interest except that it is created out of a working interest rather than out of the original mineral interest or a net operating interest.

2.124 Another interest created out of the working interest is the "production payment." Production payments are generally used to finance development of a property. The owner of a production payment is entitled to a specified share of the production of a property until a designated amount of money or product is generated from the property. After the terms of the production payment are satisfied, the interest reverts to the working interest from which it was created.

2.125 In addition to the sale of royalty or working interests and production payments, common forms of conveyances include free-well agreements, carried interests, farm-outs, and unitizations.

2.126 Under a free-well agreement, the working interest owner assigns a share of the working interest or some type of nonoperating interest to another party in return for the drilling of one or more wells on the property by the other party. If oil or gas is found, the parties immediately begin sharing revenues and expenses in the proportions called for in the contract, but neither party recovers any part of costs before sharing begins.

2.127 In cases where the working interest owner transfers all or part of the operating rights to an assignee in return for the latter's assumption of all or part of the development, the transaction is referred to as a farm-out. The assignor usually retains an overriding royalty but may retain any type of interest.

2.128 Carried-interest arrangements can be categorized into two types:

1. *Carried interest for production property life.* In this arrangement, one party (the carried party) assigns an individual portion of a lease to another party (the carrying party) to develop and operate until all costs—perhaps plus an additional percentage of such costs—have been recovered out of production from the property. At pay-out, the carried party begins to receive its share of the proceeds in excess of its share of the costs.
2. *Carried interest for period of initial development.* In this arrangement, the carried party begins to share in the revenues and expenses as soon as the carrying party recovers all costs incurred in connection with the drilling of the first well.

2.129 Another form of joint interest is a unitization. In unitization transactions owners of all interests in a geological structure agree to give up their shares in the individual properties, receiving in exchange a fractional share in the unitized properties. The interest received by each is usually in proportion to the estimated reserves contributed to the unit by that party. Properties may not be at the same stage of development, however. It may be necessary for some parties to contribute cash and others to receive cash to "equalize" the values given and received for equipment and drilling costs.

Accounting for Conveyances

2.130 Mineral property conveyances and related transactions may be classified according to their natures as sales, borrowings, exchanges of non-monetary assets, poolings of interests in joint undertakings, or some combination thereof.

2.131 Because the forms of conveyances will vary widely, are generally complex, and often will not fit exactly within the accounting literature, a thorough understanding of the form is necessary to reach a proper conclusion. In addition, the auditor should be aware that the form of the conveyance may have significant tax consequences. Guidance on accounting for conveyances can be found in paragraphs 42 through 47 of FASB Statement No. 19 for the successful efforts method and Regulation S-X, 4.10(i)(6) for the full cost method.

Commodity Derivative Activities

2.132 Oil and gas producers may be involved in commodity derivative activities. Commodities and agreements settled in commodities are not considered financial instruments. However, agreements that must be settled in cash are considered derivative financial instruments. Commodity derivative activities including swaps and option contracts linked to oil or natural gas as well as similar forward, future, and option positions, fall within the scope of FASB Statement No. 119, *Disclosure about Derivative Financial Instruments and Fair Value of Financial Instruments.*[*] FASB Statement No. 119 is effective for financial statements issued for fiscal years ending after December 15, 1994, except for entities with less than $150 million in total assets. For those entities, the effective date is for financial statements issued for fiscal years ending after December 15, 1995.

2.133 FASB Statement No. 119 prescribes new disclosures about derivatives and other financial instruments. The new disclosure requirements can be summarized as follows:

- Most disclosures about derivatives and other financial instruments will have to distinguish between instruments held or issued for trading purposes and those held or issued for purposes other than trading.
- Disclosure of the contractual (or notional) amount and nature and terms of all derivative financial instruments is required. Prior to FASB Statement No. 119, certain derivatives were exempt from this requirement.

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[*] FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities,* supersedes FASB Statement No. 119. FASB Statement No. 133 establishes the accounting and reporting standards for derivative instruments and for hedging activities and is effective for all fiscal quarters of fiscal years beginning after June 15, 1999. A brief summary of FASB Statement No. 133 is provided in paragraph 2.134 of this Guide.

- The average fair value of derivatives held or issued for trading purposes during the period should be reported.
- The net gains or losses arising from trading activities should be disaggregated and the classes of instruments giving rise to those gains or losses should be identified.
- Entities should describe the objectives and strategies for holding or issuing derivatives and identify the classes of derivatives used in achieving those objectives.
- Disclosures about accounting policies for derivatives will be expanded, and additional specific disclosures about anticipated transactions hedged with derivatives are required.
- Fair value information for all financial instruments should be presented on the face of the balance sheet or in the footnotes along with related carrying amounts and must distinguish between assets and liabilities. If those disclosures are made in more than one footnote, a summary table that contains the fair values and carrying amounts should be provided.

Accounting for Derivative Instruments and Hedging Activities

2.134 FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities,* establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, (collectively referred to as derivatives) and for hedging activities. It requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those investments at fair value. If certain conditions are met, a derivative may be specifically designated as (*a*) a hedge of the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment, (*b*) a hedge of the exposure to variable cash flows of a forecasted transaction, or (*c*) a hedge of the foreign currency exposure of a net investment in a foreign operation, an unrecognized firm commitment, an available-for-sale security, or a foreign-currency-denominated forecasted transaction. The accounting for changes in the fair value of a derivative (that is, gains and losses) depends on the intended use of the derivative and the resulting designation. FASB Statement No. 133 (paragraphs 44–47) also contains extensive disclosure requirements. FASB Statement No. 133 is effective for all fiscal quarters of fiscal years beginning after June 15, 1999. Readers should refer to the full text of the Statement when considering accounting and reporting issues related to derivative instruments and hedging activities. The FASB has established the Derivative Implementation Group (DIG) to assist the Board and its staff in providing implementation guidance regarding FASB Statement No. 133. Issues addressed by the DIG and the status of related guidance can be found at the FASB's Web site http://www.fasb.org.

Chapter 3

*Tax Considerations**

3.01 Taxes represent one of the major costs affecting oil and gas producing companies. A general understanding of the principal types of taxes and their impact on the industry is essential to planning and performing an audit of an oil and gas company's financial statements.

3.02 The discussion in this chapter is intended to be only an overview. Tax laws are subject to continuous change as a result of legislation, regulatory action, and judicial interpretation.

Income Taxes

3.03 In general, income taxes affect oil and gas operations in the same manner as they do other companies. However, the income tax provisions related to oil and gas are among the most complicated. Tax considerations affect the economics of many transactions in the industry to such an extent that they may become one of the determining factors in making decisions. This economic effect and the impact on financial reporting means that the auditor should have an understanding of some of the principal income tax considerations.

Intangible Drilling and Development Costs

3.04 Intangible drilling and development costs (IDC) represent (a) costs that are incurred incident to, and are necessary for, the drilling of wells and the preparation of wells for the production of oil and gas, as well as (b) costs for items that in themselves have no salvage value (for example, items such as a drilling contractor's footage or daily rate charges, mud and chemicals, perforating, electric logging, and cementing qualify for treatment as IDC). Items such as casing and tubing do not qualify; however, the related cost of installation does. Costs applicable to line pipe, storage tanks, and comparable costs, including installation costs, are not considered IDC (not related to the drilling and preparation of wells for production), but these costs are treated as part of the cost of tangible property.

3.05 A taxpayer may elect to deduct IDC by claiming a deduction for such costs on the tax return for the first taxable year during which the taxpayer incurred or paid such costs. A failure to deduct such costs is deemed an election to capitalize and deplete IDC. Such election is binding on the taxpayer for subsequent years.

3.06 Only a portion of IDC expenditures of an integrated oil company may be deducted in the year paid or incurred. The remaining portion may be deducted ratably over thirty-six months. An individual owning a working interest (other than through a limited business interest) in a property may elect to capitalize IDC and amortize it over a five-year period. If an individual is allocated IDC deductions through a limited partnership, such costs are subject to an election to be amortized ratably over a ten-year period. These elections are in addition to that applicable to deducting IDC. An individual may be inclined to make such elections for various reasons (for example, to avoid minimum tax payments).

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* Readers should refer to currently enacted provisions of the Internal Revenue Code for changes that have been made subsequent to the publication of this Guide.

Depletion

3.07 Producers of oil and gas are entitled to a deduction for depletion to recover capitalized leasehold costs. The costs to be recovered through depletion represent those (a) that must be capitalized in connection with acquisition of the taxpayer's interest in the property and (b) that are not recoverable through depreciation (including capitalized IDC). Such costs may represent bonuses paid to a lessor, amounts paid for a royalty interest, G&G costs required to be capitalized, and other types of expenditures related to acquisition of the interest.

3.08 Depletion deductions include cost and percentage depletion. All taxpayers are entitled to cost depletion deductions. Deductions for percentage depletion are covered by specific exceptions to a general rule that such deductions are normally not allowable with respect to oil and gas production. Percentage depletion is available to certain taxpayers under an exemption applicable to specified domestic gas wells and another exemption applicable to independent producers and royalty owners. The allowable deduction for depletion is the higher of percentage or cost depletion, determined on an individual property basis. Percentage depletion in excess of the tax-cost basis in a property is a permanent difference in determining the provision for income taxes.

3.09 The auditor should be aware of the importance attached, for tax purposes, to associating the producer with the holding of an economic interest. The holder of the economic interest in the property is the party who may be entitled to the deduction for depletion. The producer of crude oil, for windfall profit tax (WPT) purposes, is the party ultimately liable for the tax, and the holder of the economic interest is the producer. An economic interest in the property can be held by a taxpayer as the result of a direct interest held in the minerals through a fee title resulting from a lease, through an assignment from the original lessee (or previous assignees of the original lessee), or through another contractual arrangement (such as certain net profits interest arrangements). Under IRS rules, the holder of the interest must have the right to share in proceeds from the sale of the reserves rather than a right to receive compensation for services rendered.

3.10 An independent producer is defined as one who does not directly, or through a related party, engage in certain specified retailing or refining activities involving oil and gas or products derived therefrom. Independent producer status can result in substantial benefits with respect to both income taxes and WPT. From an income tax standpoint, the possession of such a status would control eligibility for deducting percentage depletion. For WPT purposes, a producer must have such status to be eligible for certain lower rates and an exemption attributable to specific types of crude oil.

Conveyances

3.11 As discussed in chapter 2, conveyances in the oil and gas industry take a wide variety of forms. In many of these transactions, the income tax treatment varies significantly from the accounting treatment. Because of the effect on the financial statements and the economic impact, conveyances should be carefully reviewed and the terms and provisions analyzed to determine the appropriate tax treatment.

Common Temporary Differences

3.12 In addition to temporary differences related to IDC deductions and depletion provisions, other common temporary differences may be encountered, depending on the method of accounting used for financial statement purposes. Paragraph 3.13 summarizes the most common temporary differences.

Exhibit 3.13

Common Temporary Differences

Temporary Difference	*Successful Efforts*	*Full Cost*	*Income Tax*
Prospecting Costs (Preacquisition exploration costs)			
G&G costs	Expense	Capitalize	(1)
Exploration Costs (Postacquisition)			
Carrying costs of undeveloped properties			
Delay rentals	Expense	Capitalize	Optional
Ad valorem taxes	Expense	Capitalize	Optional
Legal costs of title defense	Expense	Capitalize	Capitalize
Direct costs of maintaining land and lease records	Expense	Capitalize	Expense
Costs to prepare well location for drilling exploratory wells and intangible drilling costs			
Proved reserves are found	Capitalize	Capitalize	Expense (2)
No proved reserves are found	Expense	Capitalize	Expense
Dry hole contribution	Expense	Capitalize	(3)
Bottom hole contribution	Expense	Capitalize	Capitalize (3)
IDC (Development Wells)	Capitalize	Capitalize	Optional (4) (usually expense)
Disposition of Capitalized Costs			
Depletion	Expense	Expense	Expense (5)

Temporary Difference	*Successful Efforts*	*Full Cost*	*Income Tax*
Abandonments			
A property that is a portion of an amortization base becomes worthless	No loss recognized	No loss recognized	Loss recognized (6)
Book provision for abandonments	Expense	N/A	Nondeductible
Amortization base becomes worthless	Loss recognized	Loss recognized	Loss recognized (6)
Impairment valuation allowances for unproved properties	Expense	N/A	Nondeductible
Conveyances and Related Transactions	(7)	(7)	(7)
Sale of Part of an Interest Owned			
Substantial uncertainty exists concerning recovery of costs applicable to retained interest or seller has substantial obligation for future performance	No gain recognized, loss recognized	No gain or loss recognized	Gain or loss recognized (8)

NOTES

1. G&G costs are capitalized if such costs would be associated with the acquisition of a property; otherwise they are deducted.
2. Tax treatment of costs of drilling exploratory-type stratigraphic test wells is unsettled.
3. Income tax treatment is unsettled. IRS position is that dry hole and bottom hole contributions should be capitalized (Rev. Rul. 80-153). Many taxpayers continue to contend that all dry hole contributions should be expensed, as should bottom hole contributions if dry.
4. Intangible costs of drilling disposal wells are capitalized and depreciated for tax purposes. IDC related to certain carried interests should be separately identified because it may have to be capitalized for tax.
5. The difference between tax depletion and book depletion may be a temporary difference. "Tax preference" depletion (depletion in excess of basis) is a permanent difference.
6. Loss is recognized only if total property is abandoned; no deduction is taken for partial abandonments.
7. Conveyances and related transactions may cause temporary differences. Such transactions should be investigated on an individual basis to determine any differences between book and tax accounting. Consider special tax treatment of carried interests (Rev. Rul. 77-176), farm-outs, tax partnerships, and the like.

8. Conveyances of an interest where conveyer retains an overriding royalty, net profits interest, or other interest should be separately identified because tax treatment is different than when an outright sale occurs.

Windfall Profit Taxes

3.14 The WPT is an excise tax assessed on the removal of domestic crude oil. WPT liabilities are limited by a statutory provision based on defined net income from a property. For WPT purposes, "domestic crude oil" is divided into two principal categories, exempt and taxable. Exempt is defined by law and includes oil applicable to certain governmental and charitable entities, certain "front-end incentive oil," exempt stripper well oil, exempt royalty oil, and exempt Indian oil.

3.15 An independent producer, as discussed under "Depletion" in paragraphs 3.07 through 3.10, is entitled to certain benefits with respect to production attributable to a working interest owned by such a producer. Lower rates and even a complete exemption are applicable to certain specified production. Certain crude oil attributable to a qualified royalty owner's interest may also be exempt from the WPT. The exemption applies to specified limits of production attributable to a nonoperating interest (not a working interest) owned by an individual, estate, or family farm corporation.

3.16 Windfall profit subject to the WPT is limited to 90 percent of the net income from the property. Net income is defined by the statute and is computed on the basis of the property's income tax definition. An election is provided to capitalize certain injectant expenses, and a deduction is provided for "imputed cost depletion" (depletion deductions computed as though IDC and injectant expenses had been capitalized from inception, if applicable).

3.17 Administrative provisions of applicable statutes and IRS regulations impose certain reporting, certification, and data-furnishing requirements on the producer, purchaser, and operator. Failure to comply with such requirements and result in assessments for additional taxes, interest, and penalties.

3.18 The tax is normally withheld by the purchaser from the production applicable to a producer who is not an integrated oil company. Such withholding requirements may be assumed by other parties (including the producer) as the result of being able to make certain elections. The purchaser of crude oil, any party assuming the purchaser's withholding obligations, and producer not subject to withholding of the WPT on its own production are required to file excise tax returns at specific times and deposit the tax in accordance with specified schedules.

3.19 Differences between the amount of the WPT withheld and the correct amount of the applicable tax may be handled by withholding adjustments during subsequent periods. If the differences have not been adjusted through withholding, the annual report furnished to the producer may indicate that the WPT was either overwithheld or underwithheld for the calendar year covered by the report. Accordingly, the producer may be required to file an excise tax return and pay the tax due or file a claim for refund or credit covering the overwithheld WPT.

3.20 When the tax is overwithheld or excessive deposits are made due to application of the net income limitation, claims for credit or refund may be filed.

In the case of any overpayment, the producer may claim a credit against current income tax liabilities by so indicating on the applicable income tax return or by filing a claim for refund. Such returns or claims for refund are seldom prepared before the financial statements are issued; therefore, an estimate of the WPT refund is normally made for financial statement purposes.

Ad Valorem and Severance Taxes

3.21 Ad valorem and severance taxes are assessed by state and local taxing authorities. Again, a detailed coverage of ad valorem and severance taxes is not within the scope of the guide. However, the following points are worth mentioning.

- Severance and ad valorem taxes are deductible for income tax purposes. Both must be allocated to the appropriate property when calculating "net income from the property" applicable to determining limitations for percentage depletion and WPT.
- Severance and ad valorem taxes are normally applicable at the revenue-interest level (as opposed to lease operating expenses applicable at the working-interest level).

3.22 Tax reporting requirements for severance and ad valorem taxes will vary depending on the applicable state or local statutes and regulations.

Chapter 4
Internal Control Considerations

4.01 Internal control of a company engaged in oil and gas exploration and production activities may be simple or it may be very complex. The nature of a particular company's internal control is influenced by the size of the company, the degree of geographic dispersion of its operations, its types of operations (for example, operator versus nonoperator), governmental requirements, and management's information needs.

4.02 In general, internal control for oil and gas producing activities is not different from that of other types of enterprises. SAS No. 55, *Consideration of Internal Control in a Financial Statement Audit,* as amended by SAS No. 78, *Consideration of Internal Control in a Financial Statement Audit: An Amendment to SAS No. 55,* provides guidance on the auditor's consideration of an entity's internal control in a financial statement audit. It describes the components of internal control and explains how an auditor should consider internal control in planning and performing an audit. Most of the business functions of companies engaged in oil and gas exploration and production activities are similar to the corresponding functions found in other types of businesses. However, certain business functions of the exploration, development, and production activities are unique. Internal control considerations for some examples of these types of functions are discussed below. Controls discussed are not always present, nor are they required for the auditor to perform the audit in accordance with generally accepted auditing standards.

Lease Records

4.03 Accurate records of nonproducing and producing properties and the related financial obligations should be maintained. For example, failure to pay delay rental payments on time can result in the loss of a valuable asset. Also, ownership interests in oil and gas properties are often complex and may change on the occurrence of certain events. Generally, a company maintains master files of lease records that contain all essential ownership and financial obligation information. Controls for this function would normally cover authorization of updates of those master files, integrity of processing master file transactions, periodic substantiation of master file contents, and prevention of unauthorized access to or alteration of data.

Division-of-Interest File Maintenance

4.04 The revenue from oil and gas producing properties is generally divided among multiple royalty and working interest owners. The operator with responsibility for remitting the revenues to the various interest owners should have reasonable assurance that all remittances are accurately computed. Typically, information about the ownership of revenue interests will be maintained in division-of-interest master files. The controls should provide for accurate and timely updating of the information, as well as prevention of unauthorized access to or alteration of the data. Division orders should be reviewed or adequately tested by individuals who do not have control over the properties.

Joint Interest Billing

4.05 Many oil and gas exploration activities are conducted jointly by two or more participants. Generally, accounting responsibility for a project is contractually defined. The operations and allocations are governed by an operating agreement. A company conducting joint operations should have controls giving reasonable assurance that all costs attributable to joint operations are identified and recorded, that the proper participant accounts are charged, that amounts due from participants are collected, and that accurate and timely statements of account are provided to the co-owners. The importance and difficulty of administering joint interest operations are increased because such operations often involve special cost allocations, carried interest arrangements, and other complexities. Most joint interest agreements also provide the nonoperating party with the right to perform (or to have performed) joint interest audits of the operator.

Revenue and Revenue Payables

4.06 A company may receive oil and gas revenues from properties for which it is the operator as well as from properties operated by others. Controls should provide reasonable assurance that the company receives all production revenues to which it is entitled. Such controls may involve the following: periodic calibration and inspection of meters, manually gauging or witnessing the gauging of production tanks, and period-to-period comparison of production volumes. In addition, settlement reports should be reconciled to the production data regularly. Prices should be monitored to ensure that maximum allowable prices are received. For revenues received on behalf of other co-owners, the amounts to be remitted must be accurately computed based on division-of-interest file information. Provisions for royalties payable should be consistent with the basic lease or royalty agreements and any questionable areas related to the computation of royalties due may be referred to legal counsel for interpretation. Detailed trial balances of royalties in suspense should be reviewed on a regular basis, and investigations of significant balances and fluctuations should be made by an employee with no conflicting duties.

Property Accounting

4.07 The tax and financial reporting requirements of accounting for oil and gas properties are unique and complex. Generally, the cost, expense, and revenue information is accumulated at the individual lease or well level regardless of the accounting method used. Subsidiary property records should be routinely reconciled to the general ledger. Controls should provide for (1) the proper capitalization or expensing of exploration costs, (2) computation of depletion for both tax and financial reporting purposes, and (3) identification of amounts recorded for oil and gas properties that are not realizable. In addition, property records should have sufficient detail of ownership, status (abandonments, leases held for sale, operations), assigned equipment, and so on. This requires coordinating the land department, the legal department, and the accounting department. Controls should be established (1) for review of joint interest billings (JIBs) and comparison against the appropriate AFEs, (2) for review of AFEs for credits due when a project is completed, and (3) for consideration of joint interest audits on a timely basis. There should be a proper segregation of duties between those responsible for preparing an economic assessment of the value of proved or unproved properties and those who have the authority to acquire or dispose of the properties. Controls should also provide for a routine review of potential impairment.

4.08 Controls should be established to determine that property transactions are properly authorized—including the selection of properties, the amount of expenditures, the location and types of resources to explore and develop, and the levels and timing of production and inventory maintained. The timing and terms of sales or other dispositions of property should also be properly authorized.

Physical Security

4.09 The substantial investment in physical assets and the ready marketability of equipment and inventory require appropriate controls over access. Also, many sites are in rather remote areas and may be unattended for long periods of time. The construction of physical barriers and restricting access should be considered, along with detection and prevention devices. In addition, there should be specific responsibility for physical custody of assets and signature access (requisition authority).

Authorization for Expenditure

4.10 An AFE, which is a procedure for documenting authorization of large expenditures, usually contains a description of the project, a listing of budgeted expenditures, and appropriate approvals. An AFE should be required for acquisition of each major fixed asset. They are normally required for all costs incurred in acquiring leases, drilling and equipping oil and gas properties, purchasing drilling equipment and service units, constructing buildings, and other major projects. The company should have established controls to follow up on variances between actual expenditures and the amounts in the AFEs.

Cost Accruals

4.11 Operators should have controls to provide reasonable assurance that accruals are made for exploration and development costs incurred. Normally, such accruals are based on field reports (such as daily drilling reports) of estimated completion percentages of AFEs in progress. Controls should also be established to assure that estimated production expenses are accrued if significant. Nonoperating interest owners should similarly accrue payables to operators for their share of expenditures incurred. This may require controls for confirmation with the operator on properties where activities are in progress.

Government Requirements

4.12 Oil and gas producing activities are subject to numerous federal and state regulations. Noncompliance with these regulations can result in legal actions—fines, assessments, and other potential liabilities. In addition, there are certain tax regulations, such as the WPT, ad valorem taxes, and statutory depletion allowances, at both the federal and state levels. Controls should be established and competent personnel should be employed to monitor and comply with the various governmental requirements.

Related Parties

4.13 The industry's unique financing arrangements, royalty relationships, management fees, and tax partnerships—among other arrangements—tend to be conducive to related party transactions. Controls should be established to accumulate the necessary information for disclosure requirements of FASB Statement No. 57, *Related Party Disclosures*.

Nonoperated Interests

4.14 Internal control for nonoperated interests should include many of the functions described in the earlier sections of this chapter. Certain other controls may also be necessary because of limited access to the operations:

- Controls should be established to provide reasonable assurance that reports of drilling activity, production, capital projects, lease renewals, and so forth, are received in a timely fashion and are reviewed by responsible employees.
- Production revenues should be reviewed against historical records and compared with estimates. Any unusual fluctuations should be investigated and appropriately resolved.
- Consideration should be given to periodically obtaining independent evaluations of significant nonoperated properties.
- Controls should be established to assure that the need for joint interest audits is given appropriate consideration within the necessary time limits.

Chapter 5
Auditing

5.01 This chapter will assist the auditor in applying generally accepted auditing standards during audits of the financial statements of companies with oil and gas producing activities. (It is presumed that the auditor has knowledge of generally accepted auditing standards; accordingly, this guide does not expand on all the auditing considerations necessary to perform an audit in accordance with generally accepted auditing standards.) Financial accounting for oil and gas producing activities is unique in many areas and consequently presents problems for the auditor, who must determine whether the financial statements are presented in conformity with generally accepted accounting principles. This chapter is intended to identify these special accounting areas and provide general guidance on the most effective way of auditing them. Auditors should use professional judgment in applying this guidance to develop the specific audit procedures that will meet their particular needs.

Audit Focus

5.02 In audits of most oil and gas producing activities the primary focus is on the company's properties. Evaluating the accumulation and recovery of costs associated with the properties is central to the audit process and to determining whether the financial statements are presented in conformity with generally accepted accounting principles.

Audit Planning

5.03 Audit planning involves developing an overall strategy for the expected conduct and scope of the audit. SAS No. 22, *Planning and Supervision*, should be consulted for general guidance on audit planning. There are certain other factors that the auditor should consider in planning an audit of the financial statements of a company with oil and gas producing activities.

Assessing Risk

5.04 SAS No. 47, *Audit Risk and Materiality in Conducting an Audit*, provides general guidance on considerations of audit risk and materiality in planning the audit and designing audit procedures. Planning considerations will vary with—

1. The size and complexity of the entity.
2. The entity's financial condition.
3. The auditor's experience with the entity.
4. The auditor's knowledge of the entity's business.

5.05 The auditor plans the audit so that the audit risk is limited to an appropriately low level. The auditor should consider this risk in determining the nature, timing, and extent of auditing procedures and in evaluating the results of those procedures. The unique business considerations of oil and gas producing activities also play an important role in assessing audit risk and materiality. This is particularly significant when evaluating audit risk associated with account balances or class of transactions in such a specialized industry. SAS No. 47 addresses this aspect of audit risk in terms of three component risks—inherent, control, and detection risk.

5.06 Many aspects of evaluating these three component risks are not unique to auditing oil and gas producing activities. The special business factors that should be considered when the auditor is assessing these component risks in determining the nature, timing, and extent of auditing procedures are discussed within this chapter of the guide.

Nature of Operations

5.07 It is important for the auditor to consider the company's method of operation in planning the audit. Responsibilities associated with property operation will vary widely. Among matters to be considered would be the extent of operating responsibilities, the use of partnerships or joint ventures, and related party transactions.

5.08 *Operator or Nonoperator.* A distinction can be drawn between audit procedures designed to be used in the audit of the financial statements of a producer acting as an operator of properties and the audit procedures used in the audit of the financial statements of a company acting solely as a nonoperator to joint operating agreements. Some of the factors to consider are—

- The terms of the operating agreement concerning the duties and responsibilities of the operator and the rights and obligations of the nonoperators.
- Whether the operator's controls provide reasonable assurance of compliance with the provisions of the operating agreement, provide proper and prompt billing of costs and expenses to nonoperators, and provide distribution of revenues to royalty interest owners and nonoperator working interest holders.
- Whether the nonoperator's controls provide reasonable assurance of proper accounting for costs and expenses. Another factor to consider is that billings received from the operator are properly supported and in compliance with the terms of the operating agreement.
- Whether or not joint interest audits are periodically performed.

5.09 Nonoperators generally require significantly less accounting and operations personnel than would an operator. The operator will have the responsibility for paying all costs of the development and the operation of the property, properly billing such costs to the nonoperators, and often collecting and distributing revenues. On the other hand, the nonoperator pays and collects only its share of the costs and revenues (generally no more often than once a month).

5.10 *Use of Partnerships.* The use of partnerships for financing purposes usually adds significant complications to the accounting and auditing of an oil and gas company. Many companies create limited partnerships by selling limited partner interests in public or private offerings. Often, the limited partnership agreements require audits of the partnership. The auditor should be mindful that a lower materiality factor may be more appropriate for testing partnership transactions than for testing transactions of the sponsoring company, which may also be audited.

5.11 In addition, the terms of the partnership agreement would dictate the allocation of costs and revenues to the limited and general partners and often would require a determination of the status of individual properties or groups of properties within the partnership. Therefore, the auditor should be familiar with the significant provisions of the partnership agreement and, where applicable, the audit procedures should reflect these considerations.

5.12 *Related Party Transactions.* The nature of oil and gas operations tends to result in a greater frequency and significance of related party transactions than would occur in many other industries. This is largely because of the readily divisible nature of property ownership, but these transactions also occur from dealings with limited partnerships, joint ventures, and the like. Commonly encountered related-party transactions include—

- Employee interest in properties, particularly through incentive plans that enable key employees to earn an interest in successful prospects.
- Participation in properties with directors. Particularly in smaller companies, a frequent source of prospects may be directors who are themselves independent operators in the industry.
- Transactions with limited partnerships, including handling property transactions and allocating costs. Limited partnerships often involve conflicts of interest, in which decisions may benefit or adversely affect either the company or the limited partners.

5.13 In planning the audit, consideration should be given to determining that information necessary for related party disclosures is available and procedures for testing the related accounts should be designed to comply with, SAS No. 45, *Omnibus Statement on Auditing Standards—1983*, "Related Parties."

5.14 *Other Considerations.* Other contracts and agreements related to property operations that may require consideration in the planning of specific audit procedures include the following:

- Long-term sales contracts
- Drilling contracts
- Take-or-pay contracts
- Production payments
- Farm-outs and carried interests
- Leases, particularly expiration provisions
- Production-balancing contracts
- Division orders
- Regulatory agreements

Geographical Considerations

5.15 The procedures used by the auditor during an audit of an oil and gas producing company's financial statements may be greatly affected by the geographical areas in which the company operates. For example, offshore operations and operations in foreign countries may require the auditor to consider—

- Different types of property costs associated with offshore as opposed to onshore operations.
- Various environmental and other regulatory implications.
- Production-sharing contracts with foreign governments.

- Tax implications of foreign operations.
- Disclosure requirements of foreign operations.

Identifying Personnel With Specific Functions

5.16 Identifying specified personnel, and their geographic location, having the responsibility for specific functions related to accounting, internal control, and financial reporting is an integral part of planning the audit.

5.17 *Field Operation Accounting Personnel.* Field operations may be conducted in a manner whereby the accounting data for investments in, and operations of, oil and gas properties are processed in the company's home office. On the other hand, certain functions may be performed in district or field offices. The auditor identifies the personnel, and their location, responsible for specific items, such as—

- Preparing and approving AFEs and subsequently reconciling actual costs with estimates.
- Measuring and reporting units of production.
- Pricing production.
- Approving expenses and allocations to specific properties.
- Joint interest billing and revenue sharing.
- Handling warehouse receipts and issuing materials.
- Complying with regulations.

5.18 *Geological, Geophysical, and Engineering Personnel.* Financial statements and reports to management for companies with oil and gas producing activities require that certain data be made available that call for the input of personnel other than accounting department personnel. This information includes—

- Status of wells.
- Reserve data about units, production curves, future development and operating costs, and the like.
- Production data analyses of pricing, number of units, conversion factors, and so on.
- AFE data—for example, identification of capital versus expense workovers.
- Value information and exploration plans for measuring impairment and cost ceiling.

5.19 *Land Department Personnel.* These personnel may assist in providing information regarding property identification, WPT data, transfers from undeveloped properties to producing leaseholds or abandonments, or current status of contractual obligations that are applicable to leasehold rights (such as delay rental payments, drilling obligations, and payout status). When making the inquiries referred to above, the auditor should also plan to identify the procedures used by the company's personnel in accumulating, processing, and validating the data involved.

Use of Specialists

5.20 The nature of the oil and gas industry often requires the use of specialists such as reservoir engineers and geologists. Such specialists may be employees of the company or they may be independent consultants or contractors. SAS No. 73, *Using the Work of a Specialist*, provides guidance to the auditor who does use the work of a specialist in performing an audit. In addition, Auditing Interpretation No. 1 of SAS No. 52, "Supplementary Oil and Gas Reserve Information," at AU section 9558.01—.06, describes standards prepared by the Society of Petroleum Engineers for qualifications of a reserve estimator.

5.21 The auditor preferably should make an early assessment of the extent of use of specialists and the timing considerations thereof, including the need for involving independent consultants. The auditor may consider outlining those needs in an audit engagement letter.

5.22 SAS No. 83, *Establishing an Understanding With the Client*, requires the auditor to establish an understanding with the client that includes the objectives of the engagement, the responsibilities of management and the auditor, and any limitations of the engagement. The Statement requires the auditor to document the understanding with the client in the workpapers, preferably through a written communication with the client. The Statement provides guidance to the auditor for situations in which the practitioner believes that an understanding with the client has not been established.

5.23 SAS No. 83 also identifies specific matters that ordinarily would be addressed in the understanding with the client, and other contractual matters an auditor might wish to include in the understanding. Statement on Standards for Attestation Engagements No. 7, *Establishing an Understanding With the Client*, sets forth these same requirements for attestation engagements.

5.24 The extent to which an independent outside specialist is used may depend on whether a cost ceiling limitation problem is considered likely to exist. (See discussion under "Accounting for Production" in paragraphs 2.105 through 2.119.) This is a judgmental area; however, auditors should consider the advisability of requesting the involvement of an independent outside specialist when it appears the costs are approaching or may exceed the cost ceiling limitation.

Tax and Other Regulatory Matters

5.25 Various tax and other regulatory matters can have a significant impact on an oil and gas company's financial statements. The auditor should make inquiries about the status of federal and state income tax matters and severance and property-tax reporting matters. The auditor should also review the determination of the producer's status as an independent producer because of the substantial impact such a determination can have on income tax and WPT liabilities. (See discussion under "Depletion" in paragraphs 3.07 through 3.10.) In addition, certain inquiries concerning WPT should be made. These include—

- Status of depository or withholding requirements and compliance with applicable reporting requirements.
- Procedures used to test the accuracy of amounts withheld or deposited and to compute amounts refundable under the net income limitation.
- The company's reporting responsibility because of its role as general or managing partner in existing partnerships.

Other regulatory matters include—

- Pricing procedures used in, and personnel responsible for, compliance with applicable statutes and regulations.

- Reporting to state regulatory authorities (which states are involved, what reports must be filed, what procedures are used to accumulate applicable data, and so on).
- Reporting to the SEC (current status of filings, identification of data, responsible personnel, and the like).

Audit Considerations

5.26 This section identifies and discusses certain audit considerations of some of the business functions and accounts unique to oil and gas producing companies. The procedures selected to achieve the particular audit objectives should be adapted to the specific circumstances of the company. The areas discussed include property, receivables, payables, expenses, revenues, and other considerations.

Property

5.27 The tests of property accounts of companies with oil and gas producing activities require careful consideration by the auditor. Property generally represents the largest item in the balance sheet and is often the most difficult to test. Reliance is often placed on estimates by the company's operations department and management assertions. Following are several areas that deserve special attention in the tests of oil and gas property accounts:

- Property costs
- Interest capitalization
- Materials and supplies
- Conveyances
- Abandonment costs
- Dry hole costs
- Wells in progress
- Depletion, depreciation, and amortization
- Capital cost limitations

5.28 *Property Costs.* Joint interest owners share in acquisition, exploration, development, and production costs in accordance with the cost-sharing provisions of the joint operating agreement. Carried and reversionary interest provisions (among many other similar arrangements) often cause the sharing of costs to be different from the permanent lease ownership. The auditor should be familiar with the cost-sharing provisions of each property selected for testing in order to effectively audit property costs.

5.29 For cost-control purposes, an AFE is prepared for most exploratory and development drilling activities and major projects undertaken by joint interests. The AFE gives the operator approval to incur specified dollar amounts in accomplishing agreed-upon tasks. The auditor may compare actual costs incurred by the operator with AFE amounts for evidence of unauthorized or excessive expenditures. Indications of potential charges or credits from joint interest audits impending or in progress should be evaluated in accordance with FASB Statement No. 5, *Accounting for Contingencies*.

5.30 Depreciation of support equipment and facilities used in oil and gas producing activities is properly accounted for as exploration, development, or production costs, depending on the activity with which the support equipment or facilities are involved. The auditor should consider appropriate audit procedures to determine that depreciation of support equipment is properly allocated.

5.31 A standard procedure in auditing property accounts of any commercial enterprise is testing physical existence. Physical examination of many types of oil and gas property is sometimes impractical and often alternative procedures are performed. For instance, producing wells are frequently too widely dispersed and too numerous to be examined. Alternately, the auditor may examine production records maintained by the operations department to determine that production proceeds were being received on the property as of the end of the period. Likewise, leasehold rights are intangible, and ownership is evidenced only through a lease or assignment document. Absolute verification of the company's ownership in a lease would require a title search—a time-consuming and expensive process. For this reason, the auditor may test ownership by examining a lease agreement and lease file. Additionally, examination of a delay rental payment is further evidence of the company's retention of its interest in the lease. The auditor may also obtain signed representations that the subject lease was not sold, assigned, or otherwise disposed of during the period.

5.32 *Interest Capitalization.* In determining whether capitalized interest is properly accounted for, the auditor should check that the qualifying assets have not previously entered the earnings activities of the company and determine that interest capitalized is properly computed.

5.33 *Materials and Supplies.* Operators of oil and gas properties often hold or have materials and supplies (production equipment inventory) stored by independent storage yards for use in future drilling activities and operations. Frequently, equipment will be transferred to a property in which the operator has an interest. The operator charges the joint account for the equipment and bills nonoperating interest owners for their share of the equipment pursuant to the joint operating agreement. Likewise, equipment is often transferred back to a storage yard upon the abandonment of a well. The operator issues credit to the nonoperating interest owners for their share of the condition value attached to the equipment as dictated by the accounting procedures supplement to the joint operating agreement. The auditor should consider procedures to identify equipment movements and test the propriety of the accounting treatment for such movements. Depending on the extent of controls in effect, the auditor may confirm the existence of equipment with independent yards or may consider it necessary to observe the taking of a physical inventory. The auditor should determine that materials and supplies are not carried at amounts in excess of the amounts recoverable in the normal course of business through use by the operator or recovery through operating agreements; the auditor should also review for obsolescence. When materials and supplies are held for sale, the usual lower-of-cost-or-market test should be applied.

5.34 *Conveyances.* Oil and gas property conveyances can take a variety of forms, each of which may be unique. The auditor should evaluate the accounting treatment of conveyance transactions in accordance with the conveyance provisions of FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies,* and Regulation S-X. The auditor should also be aware of the considerable differences between the financial accounting and income tax treatments of conveyances in the review of the company's income tax accrual.

5.35 *Abandonment Costs.* Accounting for abandoned wells and leases is discussed under "Production" in paragraphs 2.91 through 2.119. For abandoned, unproved leases that are not expiring under their own terms, the auditor may obtain representations* from the company (1) that it does not intend to promote, develop, or sell the lease, or to pay future delay rentals when they come due and (2) that it has all necessary approvals. For leases that expire under their own terms or because of failure to perform drilling obligations, the auditor should consider appropriate procedures to determine that the company no longer has an interest in the lease and that the company has properly approved and recorded the abandonment. When wells are abandoned, the operator is required to file a plugging report with the appropriate state governmental agency. The auditor may examine the plugging report to substantiate the abandonment of the well and, where applicable, determine that proper credit was granted to joint owners for salvageable lease and well equipment.

5.36 *Dry Hole Costs.* Under the successful efforts method of accounting, dry hole costs of an exploratory well are expensed when a determination is made that the well has no proved reserves. The auditor can usually substantiate the success or failure of a drilling effort by examining drilling reports from the drilling company (or operator for nonoperating interest owners). If drilling reports are unavailable, the auditor can examine a plugging report filed by the operator as support of the unsuccessful outcome of a well.

5.37 *Wells in Progress.* The accounting treatment for costs associated with exploratory wells in progress at the end of a reporting period is unique only under the successful efforts method. Costs of an exploratory well that has not found proved reserves should be expensed. The auditor uses all information available in evaluating the status of an exploratory well as of the report date. Occasionally, a well is drilled and it cannot be immediately determined whether the property has proved reserves. This often happens because the property appears marginally economical or a major capital expenditure is required before production can begin. Usually, if a decision about the economic viability of a well cannot be made within one year, the well would be considered impaired and the costs charged to expense. A well requiring a major capital expenditure is carried as an asset only if the well has a sufficient quantity of reserves to justify its completion. If the drilling of additional wells is necessary to determine if reserves are sufficient, the company decides whether it is warranted to incur the additional capital expenditures. In addition, the drilling of the wells must have commenced or be firmly planned in the future in order to be carried as an asset. The auditor evaluates all available information to determine if capitalization of costs is proper under the above criteria.

5.38 *Depletion, Depreciation, and Amortization.* The methods used in computing DD&A under the full cost and successful efforts methods are discussed under "Production" in paragraphs 2.91 through 2.119. The key to auditing DD&A is to substantiate the DD&A rate and the DD&A cost base to which the rate is applied. In testing the DD&A rate, the auditor should inquire about the methods and bases used in the reserve study and their consistency with other available information. Current-year production quantities may be tested in conjunction with the testing of oil and gas production revenues. The cost base to which the DD&A rate is applied pertains to each cost center under the full cost method and on a property-by-property or an aggregation-of-properties basis under the successful efforts method. The auditor should test

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* SAS No. 85, *Management Representations*, establishes a requirement that an auditor, performing an audit in accordance with generally accepted auditing standards, obtain written representations from management for all financial statements and periods covered by the auditor's report. The Statement also provides guidance concerning the representations to be obtained, along with an illustrative management representation letter.

the cost base used in the computation and determine if all costs excluded from the cost base are properly excludable. The full cost method requires including estimated future development costs in the company's cost base. The auditor should review the company's estimated future development costs; determine if they are reasonable, given estimated future development activity; and compare them to the reserve report. The auditor should also determine whether these costs are based on current costs.

5.39 Unproved properties are periodically assessed to determine if they have been impaired. (Accounting for impairment of unproved property costs is discussed under "Acquisition of Mineral Properties" in paragraphs 2.01 through 2.30.) The auditor should review the company's procedures in providing for impairment and evaluate the adequacy of the provision. In evaluating the adequacy of the impairment provision, the auditor should use such information as the company's plans, dry holes drilled in areas near the company's leases, and lease expiration dates, because it is more likely that impairment exists on leases whose expiration dates are approaching. The auditor should be aware that top leases may be impaired by drilling activities of the original lessee, whether successful or not.

5.40 *Capital Cost Limitations.* The full cost method prescribes a ceiling test for capitalized costs. The auditor should review the components of the cost ceiling computation to determine that they are computed in accordance with the prescribed guidelines. The rationale behind the ceiling test is that oil and gas property costs should be recoverable from the underlying assets. Therefore, any capitalized costs—net of accumulated DD&A and related deferred income taxes—in excess of the ceiling are written off to expense. In those situations where costs approach or exceed the ceiling, it may be advisable to consider consultation with independent outside specialists.

5.41 In contrast with the full cost method, the issue of whether to provide for impairment of proved properties based on the amount expected to be recoverable is unsettled under the successful efforts method.* The provisions of FASB Statement No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, are applicable to the costs of an enterprise's wells and related equipment and facilities and the costs of the related proved properties. (See paragraph 1.55 of this Guide for further information.) The auditor should consider audit procedures to be applied for testing impairment of long-lived assets.

Receivables

5.42 The general approach in auditing receivables from oil and gas producing activities is in many respects similar to that followed in auditing receivables of commercial enterprises. The confirmation of accounts receivable

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* FASB Statement No. 19, paragraph 209, is as follows:
209. As explained in paragraphs 190 and 191, a cost center is not the primary consideration in the capitalize/expense decision under the approach to successful efforts accounting adopted by the Board in this Statement. Under that approach, the assets to which the capitalized acquisition, exploratory drilling, and development costs relate are *properties, wells, equipment, and facilities*. The question of whether to write down the carrying amount of productive assets to an amount expected to be recoverable through future use of those assets is unsettled under present generally accepted accounting principles. This is a pervasive issue that the Board has not addressed. Consequently, this Statement is not intended to change practice by either requiring or prohibiting an impairment test for proved properties or for wells, equipment, and facilities that constitute part of an enterprise's oil and gas producing systems.

is a useful procedure for most accounts; however, special consideration should be given to the performance of additional or alternative audit procedures in the following areas:

- Joint interest billings (JIBs)
- Joint interest credits
- Oil and gas sales
- Production imbalances
- Cash calls
- Collectibility

5.43 *Joint Interest Billings.* The operator can normally confirm from nonoperating interest owners the JIB balance as of the audit date; however, the validity of joint interest receivables is often dependent solely on the operator's accuracy in preparing the underlying JIBs. Accordingly, the auditor of the operator should consider procedures to test (a) the validity and accuracy of the charges supporting the JIB statements and (b) the percentages charged to nonoperating interest owners. At the audit date the property operator may have incurred obligations on behalf of the joint owners that have not been billed. These unbilled obligations also represent JIB receivables that—except for the omission of confirmation testing—should be considered for testing by the auditor.

5.44 *Joint Interest Credits.* Nonoperating parties normally have the right to audit the accounts and records of the operator relating to the joint account. These audits often result in credits being granted to nonoperating parties. The nonoperator's auditor should determine whether the nonoperator has recorded accounts receivable for credits granted and evaluate possible credits from audits in progress or impending in accordance with the gain-contingency provisions of FASB Statement No. 5. These procedures also apply to the audit of accounts payable of an operating company where the operator is subject to issuance of potential joint interest credits.

5.45 *Oil and Gas Sales.* Oil and gas production sales are generally recorded from run tickets or remittance advices received from purchasers of the production. Remittance advices are usually received from one to three months after the purchaser takes control of the production. Oil and gas revenue transactions may be recorded on a cash basis; however, the company should accrue estimated unreceived production revenues and related WPT and production taxes at the financial statement date. Such estimates consider production volumes, revenue interests, sales price histories, and appropriate deductions. The auditor should test the accrual through appropriate means: for example, verifying production quantities used in the estimate to independent production records (or run tickets, if available), comparing revenue interest or royalty interest percentages with appropriate division orders, and substantiating the reasonableness of sales prices and tax withholdings used in the accrual.

5.46 *Production Imbalances.* Oil and gas production from a property is usually sold to purchasers for the benefit of all joint owners of that property. The purchasers then usually remit the sales proceeds to joint owners in accordance with the distribution provisions of the division order covering the property. Most standard joint operating agreements allow joint owners the option of taking their share of production in kind rather than having it sold to purchasers on their behalf. Where revenue interest owners take their share of production in kind, it is likely that the owners have taken more (overlift) or less (underlift) production than they are entitled to as of the audit date. The auditor should review the company's entitlement computation and consider confirmation procedures to substantiate any production imbalance receivables or payables recorded at the audit date.

5.47 *Cash Calls.* Under the provisions of most joint operating agreements the operator of a property can require nonoperating interest owners to advance their share of the estimated cash outlay for the succeeding month's drilling activities and producing-property operations of the joint account. In these cases, the operator is entitled to these advances upon proper notification to the nonoperating interest owners. Where applicable, the auditor should consider confirming cash calls receivable with nonoperating interest owners; the auditor should also review the operator's computations supporting the cash call to determine if the amounts requested approximate anticipated expenditures for operations in the following month.

5.48 *Collectibility.* Collectibility of joint interest accounts receivable in the oil and gas industry traditionally has not been a problem because of the remedies available to operators in the event of nonpayment or default. Operators have a preferred lien on the ownership interest of nonoperating parties. Under the provisions of the standard operating agreement, the operator can collect from oil and gas purchasers the proceeds accruing to the interest of the delinquent party up to the amount owed. Where it appears that an operator will have to collect amounts due in this manner, the auditor should determine that the delinquent party's share of future proceeds will cover the uncollected balance and the appropriate balance sheet classification. Disputes can arise over joint interest ownership percentages in oil and gas production and requested natural gas pricing classifications can be disallowed by the FERC. The auditor should inquire of company management whether such disputes or potential disallowances exist and perform appropriate audit procedures to determine that the effect of any such disputes is properly reflected or disclosed in the financial statements. Collectibility is a more serious problem when wells are plugged and abandoned or are only marginally economical, particularly if one or more of the nonoperators has financial difficulties. The operator may have the right under the operating agreement to rebill all operating interest owners for their proportionate share of the unpaid costs.

Payables

5.49 Liabilities related to oil and gas producing activities are in many ways similar to those of a typical commercial enterprise. Accordingly, procedures in these areas are not necessarily unique; however, certain liabilities deserve special attention because of their peculiarity to the oil and gas industry. Many of these liabilities arise from the various everyday activities and transactions between operators and nonoperators of joint properties. The following are some of the more unusual areas:

- Joint interest payables
- Revenue distribution
- Borrowings from production purchasers
- Unapplied advances
- Production taxes payable

5.50 *Joint Interest Payables.* JIBs sent to nonoperating interest owners from operators generally provide very little detail about the timing of exploration, development, and production expenditures incurred by the operator. Therefore, these JIBs may not be useful when nonoperating parties accrue accounts payable as of the audit date. Nonoperating interest owners accrue these expenditures based on the best available information from the company's operations department (or from the operator if more accessible). Usually, such information can be adequately estimated from a schedule of AFEs, which details all open AFEs, AFE costs, the company's working interest in the related properties, and the completion percentage of each AFE. The auditor should consider appropriate audit procedures to substantiate the completeness of the schedule of open AFEs and review the AFE data contained in the schedule with operations personnel for reasonableness.

5.51 *Revenue Distribution.* Production revenues generated from a property are distributed by purchasers in accordance with the provisions of the division order executed by the joint owners of the property. Joint owners often collect production proceeds on behalf of other joint or royalty owners and make appropriate disbursements to them on a periodic basis. At the audit date, a proper cutoff is important. The party designated to collect such proceeds accrues accounts receivable (revenues net of tax withholdings) with an offset to a payable-to-royalty-owner's account. Depending on taxing jurisdiction regulations or contractual agreements, the responsibility for payment of severance or production taxes may lie with the purchaser, the operator, or the working interest owners individually. Occasionally, proceeds collected are in dispute and are recorded in a suspense account. This type of liability is not relieved until the dispute is resolved. The auditor should consider appropriate audit procedures to identify those properties on which the company collects revenues on behalf of royalty and other joint owners. Special attention should be given to suspense payables, as they may accumulate over extended periods of time before the underlying disputes are resolved.

5.52 Under the terms of many lease agreements, lessors are entitled to shut-in well payments, mandatory or minimum royalty payments, and payments of a similar nature. As of the balance sheet date, lessees accrue such mandatory payments to lessors. The auditor should identify potential obligations and determine their proper treatment in the financial statements by interviewing operations personnel and performing audit procedures.

5.53 *Borrowings From Production Purchasers.* Enterprises seeking sources of oil and gas supplies sometimes advance cash to property owners to finance exploration or development. The auditor may confirm borrowings and thus be satisfied that the terms of the borrowing arrangement have been complied with. The auditor should consider tests to determine the substance of the transactions involving advances from purchasers because they sometimes take the form of mineral sales whose treatment is addressed under "Conveyances" in paragraphs 2.120 through 2.131.

5.54 *Unapplied Advances.* As discussed previously, property operators may call nonoperating parties for cash advances to cover the estimated expenditures to be incurred in the following month's operations. As the operator incurs expenditures on behalf of nonoperating interest owners, their share of the expenditures is applied against advances received. Unapplied advances as of the financial statement date are liabilities to nonoperating interest owners and may be confirmed by the auditor. Joint interest owners will usually be able to confirm only the advances made to the operator, less reductions for their share of expenditures incurred as represented on JIBs received from the operator. The validity of JIBs depends on the operator's accuracy in preparing them. The nonoperator's auditor should consider procedures to test the reasonableness of the JIB statements.

5.55 *Production Taxes Payable.* Production taxes are payable to state or other governmental agencies by either the purchaser or producer as determined by state or other governmental agencies. Where the producer is liable for the taxes, the operator usually pays production taxes on behalf of all joint interest owners. The auditor should determine that the operator has properly recorded the liability for state taxes and test the propriety of recorded production taxes payable.

Expenses

5.56 This section deals with expenditures and other charges (*a*) that are classified as expenses under both the successful efforts and full cost methods and (*b*) that are unique to the oil and gas industry. This section does not deal with expenses arising from the amortization or write-off of assets such as abandonment expenses, depletion and depreciation expense, amortization expense, and the like. (These expenses are dealt with under "Property" in paragraphs 5.31 through 5.37.) Three types of expenses that should be given special consideration are (*a*) work-over expense, (*b*) district and warehousing expenses and administrative overhead, and (*c*) WPT expense.

5.57 *Work-Over Expense.* AFEs may be prepared for well work-overs where charges are expected to exceed a minimum amount. The auditor should determine the nature of well work-overs and then test the propriety of the company's classification of the work-over charges as capital or expense items. In addition, actual charges should be compared with the AFE (where an AFE has been prepared), and a determination and evaluation should be made of any apparent excessive or unauthorized charges.

5.58 *Overhead.* The operator of a property is usually entitled to be paid by the joint venture for certain overhead charges as compensation for administrative, supervisory, office service, and warehousing costs. The accounting procedures supplement to the joint operating agreement specifies the types and often the amount of charges that can be allocated to the joint account for such overhead. The nonoperator's auditor should consider procedures (1) to test the reasonableness of the allocated charges under the accounting procedures supplement and (2) to test that the company was charged for its proper share of the expenses.

5.59 *WPT Expense.* WPT expense will normally be composed of two components: taxes withheld from revenues by purchasers (debits) and the estimate of taxes to be refunded because of the effect of the net income limitation (credits). Companies normally estimate the refund based on prior year refunds or well-by-well computations. Usually, detailed computations are not available by the time the auditor is required to report on the financial statements. Consequently, the auditor will be required to use a high degree of judgment to determine whether the estimate is reasonable. Analytical procedures can often be helpful. Among the factors to be considered are the relationship of taxes withheld to oil sales and lease operating expenses, prior year refund experience, changes in the company's status or types of wells, and fluctuations in production volumes.

Revenues

5.60 Revenues from oil and gas producing activities are typically of two types: production revenues and property conveyances. The following are items that may be considered by the auditor in conducting an audit of these revenues:

- Sharing-in and accountability for oil and gas sales
- Pricing regulations and contractual agreements

- Property conveyances
- Revenue accumulation
- Take-or-pay contracts

5.61 *Sharing-in and Accountability for Oil and Gas Sales.* Oil and gas sales may be recorded from purchase remittance advices received from oil and gas purchasers. The auditor should consider tests to determine if production quantities on which sales proceeds were received agree to independent production records that have been maintained by the operations department to substantiate that the company is receiving its proper share of revenues generated from a property or properties. The sharing of oil and gas production revenues by joint owners can be affected by a number of different arrangements. For instance, many joint interest drilling ventures call for joint interest owners to drill a free well or incur a higher percentage of the drilling costs (carried interest) than their permanent ownership interest in the property in return for contributions (for example, leasehold and exploration expenses) by other joint interest owners in the venture. Often these joint interest owners are entitled to all or to a proportionately higher interest in generated production revenues until they recover a specified amount of costs. When these costs are recovered, their revenue interest reverts to their permanent interest in the property.

5.62 Another common arrangement occurs when a joint interest owner declines participation (nonconsents) in drilling, deepening, completing, plugging back, or reworking a well. The consenting parties must then incur proportionately higher costs to perform the specified task and, accordingly, are entitled to all of the nonconsenting parties' interest in generated revenues until they recover a predetermined percentage of their actual costs incurred. This percentage is commonly in excess of 100 percent of actual costs to compensate the consenting parties for their risk in the venture.

5.63 Various other such arrangements exist that can alter the sharing of revenues. The auditor should consider examining division orders and other substantive evidence to test the propriety of the company's revenues. Testing oil and gas revenues can often be accomplished in conjunction with tests of oil and gas properties by determining that revenue recorded, if any, is reasonable in relation to the status of the property, the engineering reports, and the historical records.

5.64 *Pricing Regulations and Contractual Agreements.* Oil and gas producing activities are subject to complex pricing and tax regulations governing oil and gas sales. In testing oil and gas revenue, the auditor should consider procedures to determine if the company is receiving maximum allowable prices (in some cases the market will not bear the maximum allowable price) or prices in excess of existing price ceilings, which may require future refunds. In first-year audits, compliance procedures should be considered to determine if potential refunds exist from excessive prices received from prior year oil and gas sales.

5.65 Natural gas producers may contract with purchasers to sell certain quantities of their production at specified prices. The auditor should consider testing the prices received for natural gas to determine (a) if they agree with the terms of related contracts and (b) if they comply with applicable regulations.

5.66 *Property Conveyances.* Accounting for oil and gas property conveyances is complex and should be reviewed by the auditor to determine if they are recorded in accordance with their underlying substance and applicable accounting pronouncements. From a revenue standpoint, the primary concern in testing conveyances is to determine that the company is immediately recognizing or deferring income, as appropriate. Although the accounting treatments are complex, audit procedures necessary to test conveyance transactions are not particularly unusual and will not be discussed further here. The auditor should be alert for future obligations that often accompany conveyance transactions and that may affect the accounting treatment and the possible need for footnote disclosure. It is important that the auditor obtain an understanding of the economics of the transaction to properly evaluate the accounting treatment.

5.67 *Revenue Accumulation.* Oil and gas producing companies should accumulate revenue and expense data on a property-by-property basis. Financial data on a detail property basis are needed for several reasons, including computation of the WPT net income limitation, royalty payments, percentage depletion computations, income tax obligations, and internal decision-making concerning the economics of individual properties. Since the auditor is concerned with this same data for auditing purposes, tests to determine that detail property data are properly accumulated should be considered. The auditor may then be able to rely on this financial data in other related audit areas.

5.68 *Take-or-Pay Contracts.* Sometimes gas producers and purchasers execute agreements whereby a purchaser agrees to take or pay for a minimum quantity of gas per year. Usually, any amount paid in excess of the price of gas taken is recoverable from future purchases in excess of minimum quantities. If the purchaser is not allowed to make up deficiencies, it is appropriate for the producer to record revenues to the extent of the minimum contracted quantity, assuming payment has been received or is reasonably assured. If deficiencies can be made up, receipts in excess of actual sales should be recorded as deferred revenues until production is actually taken or the right to make up deficiencies expires. The auditor should consider examining such contracts to determine the propriety of the accounting treatment and to identify possible contingencies. In addition, these contracts may impose an obligation on the producer to furnish a minimum amount of product. To the extent such product cannot be produced from the property, the producer may have a contingent liability to obtain the product from third parties. The auditor should evaluate such contingencies for possible losses or disclosure.

Other Audit Considerations

5.69 Other considerations that the auditor should address in auditing oil and gas companies include nonoperators, joint ventures and partnerships, and reserve quantity and value disclosures.

5.70 *Nonoperators.* A company with direct investments in oil and gas producing activities should maintain its own controls and accountability for nonoperators' properties. However, in some instances, particularly when the nonoperator is a passive investor with little or no industry experience, the company may not have the personnel or procedures to provide adequate oversight over costs and revenues related to nonoperated properties. In these instances, it may be necessary for the auditor to extend the audit tests to achieve the necessary level of assurance with respect to the recorded amounts.

5.71 The auditor may, in rare instances, encounter situations in which the nonoperator does not have sufficient documentation to establish the reasonableness of recorded amounts with respect to oil and gas producing activities. Normally, sufficient documentation can be requested from the operator to provide the support for the recorded amounts or to enable the necessary adjustments to be made. As an alternative, it may be more efficient for the auditor to visit the operator and examine directly the accounting records related to the specific properties. Examples of some of the audit procedures that can be performed through requesting additional documentation or visiting the operators' office are—

- Examining third-party charges to support JIBs or revenue distributions to the nonoperator.
- Examining land department records to ensure timely payments of delay rentals and timely receipt of title opinions and curatives.
- Reviewing operating agreements to ensure that overhead and similar charges are in compliance with those documents.
- Reviewing division orders and comparing with operators' disbursements of revenues to the various interest owners to determine that revenues from production have been properly allocated and remitted to the royalty and working interest owners.

5.72 *Joint Ventures.* The unincorporated joint venture is the most prevalent type of joint interest arrangement used by companies to share the risk of exploring for and developing oil and gas properties. An interpretation of APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock,* states that pro rata consolidation of the assets, liabilities, revenues, and expenses of unincorporated joint ventures is often used where it is established industry practice, as is the case in the oil and gas industry. The auditor should review and understand the structure of unincorporated joint ventures to determine if the company accounts for its investment in such joint ventures properly.

5.73 *Reserve Quantity and Value Disclosures.* Public companies with oil and gas producing activities are required by the SEC and the FASB to present certain supplementary reserve quantity and reserve value information outside of the basic financial statements. Although this supplementary information is not required to be audited, it is required to be disclosed by FASB Statement No. 69, *Disclosures About Oil and Gas Producing Activities.* The contents of the supplementary reserve quantity and reserve value disclosure information are defined in FASB Statement No. 69. The auditor is required by SAS No. 52, *Omnibus Statement on Auditing Standards—1987,* "Required Supplementary Information," and Auditing Interpretation No. 1 of SAS No. 52, "Supplementary Oil and Gas Reserve Information," at AU section 9558.01—.06 to perform certain procedures with respect to the reserve information.

5.74 The auditor's objectives in applying procedures to the supplementary disclosures are threefold:

1. To determine that the supplementary information prepared by the company is in conformity with prescribed guidelines and is presented in a manner consistent with prior year presentations
2. To determine that reserve quantity estimates are prepared by persons with appropriate qualifications
3. To determine that the reserve information is consistent with the information in the underlying financial statements

5.75 To meet these objectives, the auditor should apply the procedures specified in SAS No. 52 and the interpretation cited above. Performing those limited procedures, along with any additional procedures the auditor considers necessary, should give the auditor an adequate basis in determining whether the reserve quantity and reserve value information is presented in accordance with prescribed guidelines. However, an additional consideration may be appropriate. Independent reservoir engineers often use and rely on information, without corroboration, provided by the company in formulating their reserve quantity information. This information includes listings of the company's properties, the company's ownership interest in the properties, production data, prices, and so on. The auditor should consider appropriate tests to determine if the information provided to the reservoir engineer is complete. The auditor need not refer to the supplementary information in the auditor's report because the supplementary information is unaudited. However, the following deficiencies require the auditor to expand the auditor's report:

- Supplementary information is omitted.
- Supplementary information departs materially from generally accepted accounting principles.
- The auditor is unable to complete the prescribed procedures because of the unavailability of necessary information.

5.76 The auditor evaluates the reasonableness of the supplementary information based on the performance of the limited procedures and determines whether an appropriate expansion of the report is needed.

Appendix A

Illustrative Financial Statements and Supplemental Information

The following financial statements illustrate oil and gas disclosures and highlight financial reporting differences between the successful efforts and the full cost methods of accounting. These statements do not represent a typical set of financial statements—nor are they necessarily complete because more or less detail in the financial statements or in the notes may be appropriate, depending on the circumstances. Footnote references are included to facilitate the locating of descriptive disclosures. Blanks in the financial statements indicate captions that are not applicable to the accounting method indicated. There is no intended correlation between the amounts in the successful efforts financial statements and the amounts in the full cost financial statements. The financial statements include certain disclosures that are required only for public companies. The notes to the financial statements are representative of the basic type of disclosure for an entity with oil and gas producing activities. Additional disclosures, such as information concerning subsequent events, pension plans, postretirement benefits other than pensions, postemployment benefits, lease commitments, accounting changes, off-balance-sheet risks, concentrations of credit risk, and other matters not unique to entities with oil and gas producing activities may be required by generally accepted accounting principles.

Independent Auditor's Report

The Stockholders and Board of Directors
XYZ Oil Company

We have audited the accompanying consolidated balance sheet of XYZ Oil Company as of December 31, 19X2, and the related consolidated statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of XYZ Oil Company as of [at] December 31, 19X2, and the consolidated results of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

[*Firm Signature*]
Certified Public Accountants

City, State
February 18, 19X3

Exhibit A

XYZ OIL COMPANY

Consolidated Balance Sheet

December 31, 19X2

Assets	*Successful Efforts*	*Full Cost*
Current assets		
Cash	$ 1,200	$ 1,200
Receivables		
Trade	3,000	3,000
Affiliated partnerships	1,500	1,500
Materials and supplies	500[a]	500[a]
Oil and gas leases held for resale	800[b]	
Total current assets	7,000	6,200
Oil and gas properties, using successful efforts/full cost accounting (Notes 4, 5, and 6)		
Proved properties	9,500	
Unproved properties	6,000	
Wells and related equipment and facilities	4,000	
Support equipment and facilities	1,000	
Drilling in progress	4,000	
Materials and supplies	500[a]	
Properties being amortized		40,800
Properties not subject to amortization		9,500
	25,000	50,300
Less accumulated depreciation, depletion, amortization, and impairment	4,800	10,700
Net oil and gas properties	20,200	39,600
Other assets		
Other property and equipment, less accumulated depreciation of $300	700	700
Oil and gas leases held for resale	1,500[b]	
Other	600	600
Total other assets	2,800	1,300
	$30,000	$47,100

[a] Tubular goods inventories, as well as inventories of other oil field materials and supplies, may be classified as current assets or as oil and gas properties, depending on the intended use of the material.

[b] Oil and gas leases held for resale may be classified as current assets or as noncurrent assets. The criteria for classification of these leases are the same as for any other asset (for example, whether the leases will be sold for cash or contributed as an investment in an oil and gas limited partnership).

Liabilities and Shareholders' Equity	*Successful Efforts*	*Full Cost*
Current liabilities		
Current portion of long-term debt (Note 6)	$ 700	$ 700
Accounts payable		
Trade	3,850	3,850
Revenue distribution	800	800
Drilling advances (Note 7)	900	900
Accrued expenses	850	850
Total current liabilities	7,100	7,100
Long-term debt (Note 6)	7,700	7,700
Deferred tax liability, net (Note 8)	2,500	6,500
Deferred credit (Note 4)	1,400	
Commitments and contingencies (Note 9)		
Shareholders' equity		
Common stock, par value $1 per share; 10,000 shares authorized; 1,000 shares outstanding	1,000	1,000
Additional paid-in capital	2,000	2,000
Retained earnings	8,300	22,800
Total shareholders' equity	11,300	25,800
	$30,000	$47,100

See notes to consolidated financial statements.

Exhibit B

XYZ OIL COMPANY

Consolidated Statement of Income*

Year Ended December 31, 19X2

	Successful Efforts	*Full Cost*
Revenues		
Oil and gas sales	$14,000	$14,000
Management fees, net of related expenses of $200	100	
Sale of oil and gas leases[c]	1,000	
Gain on sale of oil and gas properties (Note 4)	2,000	
Other	400	400
Total revenues	17,500	14,400
Expenses		
Lease operating	1,000	1,000
Production and windfall profit tax	1,000	1,000
Exploration	5,000	
Depreciation, depletion, and amortization[d]	1,500	2,500
Cost of oil and gas leases sold[c]	600	
Interest	1,500	1,700
General and administrative (Note 2)	1,900	1,900
Total expenses	12,500	8,100
Income before provision for income taxes	5,000	6,300
Provision for income taxes (Note 8)	1,750	2,350
Net income	$ 3,250	$ 3,950

See notes to consolidated financial statements.

* FASB Statement No. 130, *Reporting Comprehensive Income*, establishes standards for the reporting and display of comprehensive income and its components. The Statement requires that all items that are required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. The Statement does not require a specific format for that financial statement but requires that an enterprise display an amount representing total comprehensive income for the period in that financial statement. The Statement does not apply to an enterprise that has no items of other comprehensive income in any period presented.

[c] Some companies report the gain or loss from sales of oil and gas leases held for resale rather than the sales price and related cost.

[d] If a write-down of oil and gas properties was recorded as a result of impairment or a capitalized cost ceiling limitation, the write-down may be reported as a separate expense item or included with depreciation, depletion, and amortization expense and separately disclosed.

Exhibit C

XYZ OIL COMPANY

Consolidated Statement of Cash Flows
Year Ended December 31, 19X2

	Successful Efforts	*Full Cost*
Cash flows from operating activities:		
Net income	$ 3,250	$ 3,950
Adjustments to reconcile net income to operating cash flow		
Depreciation, depletion, and amortization	1,500	2,500
Gain on sale of oil and gas properties	(2,000)	
Deferred income taxes	450	1,050
Increase in receivables	(1,500)	(1,500)
Decrease in materials and supplies	150	150
Increase in oil and gas leases held for resale	(200)	
Increase in current portion of long-term debt	200	200
Increase in accounts payable	1,250	1,250
Increase in drilling advances	200	200
Increases in accrued expenses	150	150
Increase in income taxes payable	150	150
Net cash provided by operating activities	3,600	8,100
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	5,600	6,600
Purchase of oil and gas leases held for resale	(500)	
Capital expenditures for property and equipment	(8,600)	(14,600)
Net cash used for investing activities	(3,500)	(8,000)
Cash flows from financing activities:		
Proceeds from additions to long-term debt	4,300	4,300
Payments to reduce long-term debt	(4,000)	(4,000)
Net cash provided by financing activities	300	300
Net increase in cash and cash equivalents	400	400
Cash and cash equivalents at beginning of year	800	800
Cash and cash equivalents at end of year	$ 1,200	$ 1,200
Supplemental disclosure of cash flow information:		
Cash paid during the year for income taxes	$ 1,150	$ 1,150
Cash paid during the year for interest	700	1,100

See notes to consolidated financial statements.

Exhibit D

XYZ OIL COMPANY

Notes to Consolidated Financial Statements

Year Ended December 31, 19X2

1—Summary of Significant Accounting Policies

Nature of operations and summary of significant accounting policies

Nature of operations

The Company is engaged primarily in the acquisition, development, production, exploration for, and the sale of, oil, gas and natural gas liquids. The Company sells its oil and gas products primarily to domestic pipelines and refineries.

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Principles of consolidation

The consolidated financial statements include the accounts of XYZ Oil Company, its wholly owned subsidiaries, and its proportionate share of the assets, liabilities, revenues, and expenses of all affiliated oil and gas partnerships for which the Company is the general partner.[e] All significant intercompany accounts and transactions have been eliminated in consolidation.

Materials and supplies

Inventories, consisting primarily of tubular goods and oil field materials and supplies, are stated at the lower of cost or market, cost being determined by the average cost method.

Oil and gas properties

(successful efforts)

The Company uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved proper-

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[e] It is also acceptable to account for investments in oil and gas partnerships using the equity method of accounting.

ties are amortized based on the Company's experience of successful drilling and average holding period. Capitalized costs of producing oil and gas properties, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method.[f] Support equipment and other property and equipment are depreciated over their estimated useful lives.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion, and amortization with a resulting gain or loss recognized in income.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

(full cost)

The Company follows the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with acquisition, exploration, and development of oil and gas reserves, including directly related overhead costs, are capitalized.

All capitalized costs of oil and gas properties,[g] including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves.[h] Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs.[i] If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In addition, the capitalized costs are subject to a "ceiling test," which basically limits such costs to the aggregate of the "estimated present value," discounted at a 10-percent interest rate of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income.

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[f] Some companies record the additional depreciation, depletion, and amortization (DD&A) allowance (resulting from inclusion of these estimated costs in the DD&A calculation) as an accrued liability on the balance sheet, rather than as an increase in accumulated DD&A.

[g] In some cases it may be more appropriate to depreciate natural gas cycling and processing plants by the unit-of-production method; therefore, the costs of such plants may be included in the full cost pool.

[h] It is also acceptable, if economic circumstances (related to the effects of regulated prices) indicate, to use units of revenue as a basis for computing amortization.

[i] Prior to 1983 and the adoption of SEC Release FR-14, section 406.01.c.i., only unusually significant investments in unproved properties and major development projects were eligible for exclusion from amortization.

Abandonments of properties are accounted for as adjustments of capitalized costs with no loss recognized.

Oil and gas leases held for resale

(successful efforts)

The Company has acquired certain oil and gas leases for the purpose of contributing the leases to affiliated oil and gas partnerships or for the purpose of selling the leases to industry partners for cash consideration. Such leases held for resale are periodically reviewed to determine if they have been impaired. If impairment exists, a loss is recognized by providing an impairment allowance. Abandonments of oil and gas leases held for resale are charged to expense. With respect to leases transferred to affiliated oil and gas partnerships, the determination of recovery of total costs is made on a partnership-by-partnership basis.

Capitalized interest

(successful efforts)

The Company capitalizes interest ($800 in 19X2) on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use.

(full cost)

The Company capitalizes interest ($600 in 19X2) on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use.

Management fees

(successful efforts)

In connection with the sponsorship of oil and gas partnerships, the Company receives a management fee of 3 percent from partnership subscriptions, which is credited to income as earned.

(full cost)

In connection with the sponsorship of oil and gas partnerships, the Company receives a management fee of 3 percent from partnership subscriptions. Any excess of this management fee over the related costs of registration and sale of the partnership interests is credited to oil and gas properties as a component of the full cost pool.

Cash and cash equivalents

Cash and cash equivalents include cash in banks and certificates of deposit which mature within three months of the date of purchase.

Long-lived assets

Long lived assets to be held and used are reviewed for impairment whenever events or changes in circumstances indicate that the related carrying amount may not be recoverable. When required, impairment losses on assets to be held and used are recognized based on the fair value of the asset and long-lived assets to be disposed of are reported at the lower of carrying amount or fair value less cost to sell.

Income taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the amount of taxable income and pretax financial income and between the tax bases of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled as prescribed in FASB Statement No. 109, *Accounting for Income Taxes.* As changes in tax laws or rate are enacted, deferred tax assets and liabilities are adjusted through the provision for income taxes.

2—Affiliated Oil and Gas Partnerships

The Company generally acquires, explores, and operates oil and gas properties for its own account; however, since 19X0 the Company has sponsored the formation of limited partnerships for the purpose of conducting oil and gas exploration, development, and production activities on certain oil and gas properties. The Company serves as general partner for these partnerships and, as such, has full and exclusive discretion in the management and control of the partnerships. The partnership agreements generally provide that the limited partners pay 99 percent of the cost of acquiring and operating the partnership properties, and of drilling, equipping, completing, and operating the partnership properties while the Company pays the remaining 1 percent of such costs. Revenues from partnership oil and gas properties are allocated 99 percent to the limited partners and 1 percent to the Company, until such time as the limited partners have recovered their investment in the partnership. Thereafter, partnership revenues are allocated 85 percent to the limited partners and 15 percent to the Company.

The Company is periodically reimbursed by the partnerships for certain overhead costs incurred on their behalf. In 19X2 these reimbursements totalled $750 and are reflected as a reduction in general and administrative expense in the accompanying consolidated financial statements.[j]

3—Related Party Transactions

The Chairman of the Board of Directors of the Company owns a 25-percent interest in a drilling contractor and a 10-percent interest in an oil field tool-rental company that provide services to the Company. Before engaging these companies to perform services, the Company obtains competitive bids from independent companies offering similar services. During 19X2 the Company or its affiliated oil and gas partnerships paid $1,000 and $150 to each company, respectively, for services performed.

During 19X2 the Company purchased oil and gas leases from the president of the Company for an aggregate purchase price of $100. The prices paid for the leases represented market prices for similar leases in the areas.

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[j] It is acceptable to record these reimbursements as revenues.

4—Sale of Interests in Oil and Gas Properties

(successful efforts)

In 19X2, the Company completed the sale of the following oil and gas properties, which were not carried as oil and gas leases held for resale.

In February 19X2, the Company sold its entire interest in the ABC field, a proved property, for $3,000. The Company recorded a gain from this transaction of $2,000.

In July 19X2, the Company sold a partial interest in the DEF prospect, a block of unproved acreage, for $1,600. The Company's cost in the prospect totalled $200; however, since the Company anticipates incurring over $2,000 in exploration and development costs relating to the interest retained in the prospect, the Company has recorded a deferred credit of $1,400. As exploration and development costs are incurred on this prospect, they will be charged against the deferred credit.

In December 19X2, the Company sold a partial interest in the GHI prospect, a block of unproved acreage, for $1,000. The net book value of these properties totalled $1,500 at the time of the sale; consequently, the entire sales proceeds have been recorded as a reduction of the Company's cost of the properties in the GHI area.

(full cost)

In 19X2, the Company completed the sale of the following oil and gas properties.

In February 19X2, the Company sold its entire interest in the ABC field, a proved property, for $3,000. Since the sale of this property did not significantly alter the relationship between capitalized costs and oil and gas reserves, the entire proceeds were credited to the full cost pool.

In July 19X2, the Company sold a partial interest in the DEF prospect, an unproved property, for $1,600, which was credited to the full cost pool.

In December 19X2, the Company sold a partial interest in the GHI prospect, an unproved property, for $1,000, which was credited to the full cost pool.

During 19X2, the Company sold several unproved leases for $1,000, which was credited to the full cost pool.

5—Oil and Gas Properties Not Subject to Amortization

(full cost)

The Company is currently participating in oil and gas exploration and development activities on an offshore block of acreage in the Gulf of Mexico. At December 31, 19X2, a determination cannot be made about the extent of additional oil reserves that should be classified as proved reserves as a result of this project. Consequently, the associated property costs and exploration costs have been excluded in computing amortization of the full cost pool. The Company will begin to amortize these costs when the project is evaluated, which is currently estimated to be 19X4. In addition, the cost of certain oil and gas leases which the Company has acquired for the purpose of contributing to affiliated oil and gas partnerships or of selling to third parties has been excluded in computing amortization of the full cost pool.

Costs excluded from amortization consist of the following at December 31, 19X2.

Year Incurred	*Acquisition Costs*	*Exploration Costs*	*Development Costs*	*Capitalized Interest*	*Total*
19X1	$2,600	$ 500	$400	$200	$3,700
19X2	1,500	3,200	500	600	5,800
Total	$4,100	$3,700	$900	$800	$9,500

6—Long-Term Debt

At December 31, 19X2, long-term debt and production payments consist of the following items.

Revolving credit agreement	$7,200
Production payment	1,200
	8,400
Less amounts due in one year	700
Long-term debt	$7,700

In 19X2, the Company renegotiated its $25,000 revolving credit agreement with a group of banks. Indebtedness under the agreement bears interest at 5 percent above a bank's prime lending rate (12 percent at December 31, 19X2) and is repayable in quarterly installments of $350, beginning September 30, 19X3. This line of credit is secured by certain producing oil and gas properties located in Texas and New Mexico. At December 31, 19X2, the unused available line of credit was $17,800.

In November 19X2, the Company received a production payment of $1,200 relating to certain oil and gas properties in Utah that are presently shut in. The Company is obligated to repay this advance plus interest at the rate of 15 percent per annum from 80 percent of the revenues received through oil and gas production from these properties.

The Company's aggregate long-term debt and production payments are estimated to be repayable annually in the following schedule.

19X3	$1,200[k]
19X4	1,800
19X5	1,700
19X6	1,600
19X7	1,400
Thereafter	700

7—Drilling Advances

During 19X2 the Company received drilling advances from joint interest owners with a remaining balance of $900 at December 31, 19X2. These advances will be applied toward the payment of drilling costs to be incurred in 19X3.

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[k] For guidance on the balance sheet classification of maturities of nonrecourse production payments, see ARB No. 43, chapter 3A, *Current Assets and Current Liabilities*, paragraph 8.

8—Income Taxes*

The provision (benefit) for income taxes includes income taxes currently payable and those deferred because of temporary differences between the financial statement and tax bases of assets and liabilities. The provision (benefit) for income taxes at December 31, 19X2 consists of the following:

	Successful Efforts	*Full Cost*
Federal income taxes:		
Current	$1,125	$1,125
Deferred	400	850
	1,525	1,975
State income taxes:		
Current	175	175
Deferred	50	200
	225	375
Total	$1,750	$2,350

Under FASB Statement No. 109, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the company's deferred tax assets (liabilities) as of December 31, 19X2 are as follows:

	Successful Efforts	*Full Cost*
Noncurrent deferred tax assets (liabilities)		
Exploration and development costs capitalized for financial purposes, expensed for tax purposes	($1,200)	($4,300)
Exploration costs capitalized for tax purposes, expensed for financial purposes	(300)	
Interest capitalized for financial purposes, expensed for tax purposes	400	300
Gain recognized on sales of oil and gas properties for tax purposes, not reported as a gain for financial purposes	(700)	(1,350)
Excess amortization of oil and gas properties for financial purposes over tax purposes	(700)	(1,150)
Deferred noncurrent tax liability, net	($2,500)	($6,500)

The reconciliation of income tax computed at statutory rates to income tax expense is as follows:

	Successful Efforts	*Full Cost*
Statutory rate	34.0%	34.0%
Excess statutory depletion	(10.0)	(5.0)
Minimum tax on tax preference depletion and capital gains	6.3	5.8
Other	4.7	2.5
Effective tax rate	35.0%	37.3%

* Pursuant to FASB Statement No. 109, deferred taxes shall be determined separately for each tax-paying component (an individual entity or group of entities that is consolidated for tax purposes) in each tax jurisdiction. The objective is to measure a deferred tax liability or asset using the enacted tax rate(s) expected to apply to taxable income in the periods in which the deferred tax liability or asset is expected to be settled or realized.

9—Commitments and Contingencies[1]

As general partner in certain oil and gas limited partnerships, the Company is contingently liable for the repayment of loans made to the partnerships. At December 31, 19X2, the outstanding balance of these loans, which are secured by the partnerships' oil and gas properties, is $5,000. The Company believes that the partnerships' assets will be sufficient to satisfy these obligations without loss to the Company.

The Company is committed to purchase up to $1,000 in limited partnership interests of a certain oil and gas limited partnership, if tendered by the limited partners. During 19X2 no such interests were tendered and no purchases were made.

10—Financial Instruments and Hedging Activities*

The Company uses option contracts to reduce the effects on its inventory of fluctuations in crude oil and natural gas prices. These instruments are effective in minimizing such risks by creating essentially equal and offsetting market exposures. The derivative financial instruments held by the Company are principally held for purposes other than trading. If the Company did not use derivative instruments, its exposure to market risk would be higher.

At December 31, 19X2, the Company's hedging activities had contracts maturing through 19X3 covering 6,200 barrels of crude oil and 13,700 Mcf of natural gas. The Company produced 7,860 barrels of crude oil (including natural gas liquids) and 12,390 Mcf of natural gas in 19X2 and had approximately 4,000 barrels of crude oil and petroleum products in its inventories at December 31, 19X2. These contracts permit settlement by delivery of commodities and, therefore, are not financial instruments, as defined. Additionally, since these contracts qualify as hedges and correlate to price movements of inventory and crude oil and natural gas production, any gains or losses resulting from market changes will be offset by losses or gains on the company's hedged inventory or production. Total unrealized gains for the Company's petroleum and natural gas hedging activities were approximately $1,260 at December 31, 19X2. Deferred gains related to anticipated transactions are not material.

The Company values its financial instruments as required by FASB Statement No. 107, *Disclosures about Fair Values of Financial Instruments.*** The

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(1) If the Company has any unusually significant commitments for exploration and development costs, those commitments should be disclosed in the footnotes.

* FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, which is effective for all fiscal quarters of fiscal years beginning after June 15, 1999, establishes the accounting and reporting standards for derivative instruments and for hedging activities. This Note will be modified to conform to the requirements of FASB Statement No. 133 in a future edition of the Guide.

** FASB Statement No. 126, *Exemption from Certain Required Disclosures about Financial Instruments for Certain Nonpublic Entities, an amendment of FASB Statement No. 107*, amends FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, to make the disclosures about fair value of financial instruments prescribed in FASB Statement No. 107 optional for entities that meet all of the following criteria:

a. The entity is a nonpublic entity.
b. The entity's total assets are less than $100 million on the date of the financial statements.
c. The entity has not held or issued any derivative financial instruments, as defined in FASB Statement No. 119, *Disclosure about Derivative Financial Instruments and Fair Value of Financial Instruments*, other than loan commitments, during the reporting period.

Note that FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, replaces paragraph 2(c) of FASB Statement No. 126 (item *c*. above) with the following—

> The entity has no instrument that, in whole or in part, is accounted for as a derivative instrument under FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, during the reporting period.

FASB Statement No. 133 is effective for all fiscal quarters of fiscal years beginning after June 15, 1999.

carrying amounts of cash, short-term debt and long-term variable-rate debt approximate fair value. The Company estimates the fair value of its long-term, fixed-rate debt generally using discounted cash flow analysis based on the Company's current borrowing rates for similar types of debt. The carrying amounts of the Company's financial instruments generally approximate their fair values at December 31, 19X2, except for its petroleum option contracts whose carrying value and fair value was $0 and $10 respectively.

11—Impairment of Long-Lived Assets

Note: FASB Statement No. 121 requires certain disclosures if an impairment loss is recognized for assets to be held and used. An example of such a disclosure is shown below:

> *Recently adopted environmental legislation in a jurisdiction where the Company has undertaken major exploration and development activities has placed significant restrictions on the use of certain equipment used by the Company. This circumstance has called into question the recoverability of the carrying amounts of these assets. As a result, pursuant to FASB Statement No. 121,* Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, *an impairment loss of $X,XXX has been recognized for this equipment and included as a component of income before income taxes under the caption "Exploration." In calculating the impairment loss, fair value was determined by reviewing quoted market prices for current sales of similar equipment.*

Exhibit E

XYZ OIL COMPANY

Supplemental Information (Unaudited)[m]

Year Ended December 31, 19X2

	Successful Efforts	Full Cost
Capitalized Costs Relating to Oil and Gas Producing Activities at December 31, 19X2		
Unproved oil and gas properties	$10,000	$16,300
Proved oil and gas properties	14,000	33,000
Support equipment and facilities	1,000	1,000
	25,000	50,300
Less accumulated depreciation, depletion, amortization, and impairment	4,800	10,700
Net capitalized costs	$20,200	$39,600
Costs Incurred in Oil and Gas Producing Activities for the Year Ended December 31, 19X2[n]		
Property acquisition costs		
Proved	$ 600	$ 600
Unproved	1,500	3,700
Exploration costs	5,000	7,800
Development costs	1,500	2,500
Amortization rate per equivalent barrel of production		3.13
Results of Operations for Oil and Gas Producing Activities for the Year Ended December 31, 19X2[n]		
Oil and gas sales	$14,000	$14,000
Gain on sale of oil and gas properties	2,000	
Gain on sale of oil and gas leases	400	
Production costs	(2,000)	(2,000)
Exploration expenses	(5,000)	
Depreciation, depletion, and amortization	(1,400)	(2,400)
	8,000	9,600
Income tax expense	(2,880)	(3,820)
Results of operations for oil and gas producing activities (excluding corporate overhead and financing costs)	$ 5,120	$ 5,780

Reserve Information[n]

The following estimates of proved and proved developed reserve quantities and related standardized measure of discounted net cash flow are estimates only, and do not purport to reflect realizable values or fair market values of the

[m] If XYZ Oil Company had an investment in an enterprise that was accounted for on the equity method, the Company's share of the investee's net capitalized costs, costs incurred, results of operations for producing activities, reserve quantities, and standardized measure of discounted future net cash flows would be required to be disclosed separately.

[n] These disclosures are presented assuming that XYZ Oil Company has operations in only one reportable geographic area. If operations are conducted in two or more reportable geographic areas, this information would be required to be reported in total and by geographic area.

Company's reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company's reserves are located in the United States.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment, and operating methods.

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent a year to reflect the estimated timing of the future cash flows.

	Oil (Bbls)	*Gas (Mcf)*
Proved developed and undeveloped reserves		
Beginning of year	5,000	20,000
Revisions of previous estimates	(100)	(2,000)
Improved recovery	100	
Purchases of minerals in place	80	
Extensions and discoveries	2,500	2,300
Production	(325)	(1,400)
Sales of minerals in place	(375)	
End of year	6,880	18,900
Proved developed reserves		
Beginning of year	4,500	13,000
End of year	6,200	16,000

Standardized Measure of Discounted Future Net Cash Flows at December 31, 19X2[o]

Future cash inflows	$210,000
Future production costs	(40,000)
Future development costs	(10,000)
Future income tax expenses	(70,000)
	90,000
Future net cash flows	
10% annual discount for estimated timing of cash flows	(12,000)
Standardized measures of discounted future net cash flows relating to proved oil and gas reserves	$ 78,000

The following reconciles the change in the standardized measure of discounted future net cash flow during 19X2.

Beginning of year	$ 66,000
Sales of oil and gas produced, net of production costs	(12,000)
Net changes in prices and production costs	(3,000)
Extensions, discoveries, and improved recovery, less related costs	29,000
Development costs incurred during the year which were previously estimated	2,500
Net change in estimated future development costs	2,000
Revisions of previous quantity estimates	(4,000)
Net change from purchases and sales of minerals in place	(5,500)
Accretion of discount	7,000
Net change in income taxes	(3,000)
Other	(1,000)
End of year	$ 78,000

[o] These disclosures are presented assuming that XYZ Oil Company has operations in only one reportable geographic area. If operations are conducted in two or more reportable geographic areas, this information would be required to be reported in total and by geographic area.

Appendix B

Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information by the Society of Petroleum Engineers of AIME

The standards included in this appendix relating to auditing of oil and gas reserve information are applicable to petroleum engineers and not to certified public accountants performing audits in accordance with generally accepted auditing standards.

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Article I—The Basis and Purpose of Developing Standards Pertaining to the Estimating and Auditing of Reserve Information[1]

1.1 The Nature and Purpose of Estimating and Auditing Reserve Information.[2] Estimates of Reserve Information are made by or for Entities as a part of their normal business practices. Such Reserve Information typically may include, among other things, estimates of (i) the proved reserves, (ii) the future producing rates from such proved reserves, (iii) the future net revenue from such proved reserves, and (iv) the present value of such future net revenue. The exact type and extent of Reserve Information must necessarily take into account the purpose for which such Reserve Information is being prepared and, correspondingly, statutory and regulatory provisions, if any, that are applicable to such intended use of the Reserve Information.

1.2 Estimating and Auditing Reserve Information in Accordance With Generally Accepted Engineering and Evaluation Principles. The estimating and auditing of Reserve Information is predicated upon certain historically developed principles of petroleum engineering and evaluation, which are in turn based on principles of physical science, mathematics and economics. Although these generally accepted petroleum engineering and evaluation principles are predicated on established scientific concepts, the application of such principles involves extensive judgments and is subject to changes in (i) existing knowledge and technology, (ii) economic conditions, (iii) applicable statutory and regulatory provisions, and (iv) the purposes for which the Reserve Information is to be used.

1.3 The Inherently Imprecise Nature of Reserve Information. The reliability of Reserve Information is considerably affected by several factors. Initially, it should be noted that Reserve Information is imprecise due to the inherent uncertainties in, and the limited nature of, the data base upon which the estimating and auditing of Reserve Information is predicated. Moreover, the methods and data used in estimating Reserve Information are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons estimating and auditing Reserve Information are required, in applying generally accepted petroleum engineering and evaluation principles, to make numerous judgments based upon their educational background, professional training and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render Reserve Information inherently imprecise.

1.4 The Need for Standards Governing the Estimating and Auditing of Reserve Information. The Society of Petroleum Engineers, a constituent society of the American Institute of Mining, Metallurgical, and Petroleum Engineers (the "Society"), has determined that the Society should adopt these Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information (the "Standards"). The adoption of these Standards by the Society fulfills at least three useful objectives.

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[1] These Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information (the "Standards") are not intended to bind the members of the Society of Petroleum Engineers (the "Society") or anyone else, and the Society imposes no sanctions for the nonuse of these Standards. Each person estimating and auditing oil and gas Reserve Information is encouraged to exercise his or her own judgment concerning the matters set forth in these Standards. The Society welcomes comments and suggested changes in regard to these Standards.

[2] Definitions are set forth in Section 2.2 for certain of the terms that are not textually defined in these Standards.

First, although some users of Reserve Information are cognizant of the general principles that are applied to data bases in determining Reserve Information, the judgments required in estimating and auditing Reserve Information and the inherently imprecise nature of Reserve Information, it has become increasingly apparent in recent years that many users of Reserve Information do not fully understand such matters. The adoption, publication and distribution of these Standards should enable users of Reserve Information to understand these matters more fully and therefore avoid placing undue reliance on Reserve Information.

Secondly, the wider dissemination of Reserve Information through public financial reporting, such as that required by various governmental authorities, makes it imperative that the users of Reserve Information have a general understanding of the methods of, and limitations on, estimating and auditing Reserve Information.

Thirdly, as Reserve Information proliferates in terms of the types of information available and the broader dissemination thereof, it becomes increasingly important that Reserve Information be estimated and audited on a consistent basis. Compliance with these Standards is a method of facilitating evaluation and comparisons of Reserve Information by the users thereof.

In order to accomplish the three above-discussed objectives, the Society has included in these Standards (i) definitions of selected terms pertaining to the estimation and evaluation of Reserve Information, (ii) qualifications for persons estimating and auditing Reserve Information, (iii) standards of independence and objectivity for such persons, (iv) standards for estimating proved reserves and other Reserve Information, and (v) standards for auditing proved reserves and other Reserve Information. Although these Standards are predicated on generally accepted petroleum engineering and evaluation principles, it may in the future become necessary, for the reasons set forth in Section 1.2, to clarify or amend certain of these Standards. Consequently, the Society may, in appropriate future circumstances, determine to amend these Standards or publish clarifying statements.

Article II—Definitions of Selected Terms

2.1 Applicability of Definitions. In preparing a report or opinion, persons estimating and auditing Reserve Information shall ascribe, to proved reserves and other significant terms used therein, the definitions promulgated by the Society or such other definitions as he or she may reasonably consider appropriate in accordance with generally accepted petroleum engineering and evaluation principles; provided, however, that (i) such report or opinion should define, or make reference to a definition of, each significant term that is used therein and (ii) the definitions used in any report or opinion must be consistent with statutory and regulatory provisions, if any, that apply to such report or opinion in accordance with its intended use.

2.2 Defined Terms. The definitions set forth in this Section 2.2 are applicable for all purposes of these Standards:

(a) Entity. An Entity is a corporation, joint venture, partnership, trust, individual or other person engaged in (i) the exploration for, or production of, oil and gas; (ii) the acquisition of properties or interests therein for the purpose of conducting such exploration or production; or (iii) the ownership of properties or interests therein with respect to which such exploration or production is being, or will be, conducted.

(b) Reserve Estimator. A Reserve Estimator is a person who is designated to be in responsible charge for estimating and evaluating proved reserves and other Reserve Information. A Reserve Estimator either may personally make the estimates and evaluations of Reserve Information or may supervise and approve the estimation and evaluation thereof by others.

(c) Reserve Auditor. A Reserve Auditor is a person who is designated to be in responsible charge for the conduct of an audit with respect to Reserve Information estimated by others. A Reserve Auditor either may personally conduct an audit of Reserve Information or may supervise and approve the conduct of an audit thereof by others.

(d) Reserve Information. Reserve Information consists of various estimates pertaining to the extent and value of oil and gas properties. Reserve Information may, but will not necessarily, include estimates of (i) proved reserves, (ii) the future production rates from such proved reserves, (iii) the future net revenue from such proved reserves, and (iv) the present value of such future net revenue.

Article III—Professional Qualifications of Reserve Estimators and Reserve Auditors

3.1 The Importance of Professionally Qualified Reserve Estimators and Reserve Auditors. Reserve Information is prepared and audited, respectively, by Reserve Estimators and Reserve Auditors, who are often assisted by other professionals and by paraprofessionals and clerical personnel. Reserve Estimators and Reserve Auditors may be (i) employees of an Entity itself or (ii) stockholders, proprietors, partners or employees of an independent firm of petroleum consultants with which an arrangement has been made for the estimating or auditing of Reserve Information. Irrespective of the nature of their employment, however, Reserve Estimators and Reserve Auditors must (i) examine the data base necessary to estimate or audit Reserve Information; (ii) perform such tests and consider such matters as may be necessary to evaluate the sufficiency of the data base; and (iii) make such calculations and estimations, and apply such tests and standards, as may be necessary to estimate or audit proved reserves and other Reserve Information. For the reasons discussed in Section 1.3, the proper determination of these matters is highly dependent upon the numerous judgments Reserve Estimators and Reserve Auditors are required to make based upon their educational background, professional training and professional experience. Consequently, in order to assure that Reserve Information will be as reliable as possible given the limitations inherent in the estimating and auditing process, it is essential that those in responsible charge for estimating and auditing Reserve Information have adequate professional qualifications such as those set forth in this Article III.

3.2 Professional Qualifications of Reserve Estimators. A Reserve Estimator shall be considered professionally qualified in such capacity if he or she has sufficient educational background, professional training and professional experience to enable him or her to exercise prudent professional judgment and to be in responsible charge in connection with the estimating of proved reserves and other Reserve Information. The determination of whether a Reserve Estimator is professionally qualified should be made on an individual-by-individual basis. A Reserve Estimator would normally be considered to be qualified if he or she (i) has a minimum of three years' practical experience in petroleum engineering or petroleum production geology, with at least one year of such experience being in the estimation and evaluation of Reserve Information; *and* (ii) *either* (A) has obtained, from a college or university of recognized stature, a bachelor's or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science or (B) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent thereof, from an appropriate governmental authority or professional organization.

3.3 **Professional Qualifications of Reserve Auditors.** A Reserve Auditor shall be considered professionally qualified in such capacity if he or she has sufficient educational background, professional training and professional experience to enable him or her to exercise prudent professional judgment while acting in responsible charge for the conduct of an audit of Reserve Information estimated by others. The determination of whether a Reserve Auditor is professionally qualified should be made on an individual-by-individual basis. A Reserve Auditor would normally be considered to be qualified if he or she (i) has a minimum of ten years' practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in the estimation and evaluation of Reserve Information; *and* (ii) *either* (A) has obtained, from a college or university of recognized stature, a bachelor's or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science *or* (B) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent thereof, from an appropriate governmental authority or professional organization.

Article IV—Standards of Independence, Objectivity and Confidentiality for Reserve Estimators and Reserve Auditors

4.1 **The Importance of Independent or Objective Reserve Estimators and Reserve Auditors.** In order that users of Reserve Information may be assured that the Reserve Information was estimated or audited in an unbiased and objective manner, it is important that Reserve Estimators and Reserve Auditors maintain, respectively, the levels of independence and objectivity set forth in this Article IV. The determination of the independence and objectivity of Reserve Estimators and Reserve Auditors should be made on a case-by-case basis. To facilitate such determination, the Society has adopted (i) standards of independence for consulting Reserve Estimators and consulting Reserve Auditors and (ii) standards of objectivity for Reserve Auditors internally employed by Entities to which the Reserve Information relates. To the extent that the applicable standards of independence and objectivity set forth in this Article IV are not met by Reserve Estimators and Reserve Auditors in estimating and auditing Reserve Information, such lack of conformity with this Article IV shall be set forth in any report or opinion relating to Reserve Information which purports to have been estimated or audited in accordance with these Standards.

4.2 **Requirement of Independence for Consulting Reserve Estimators and Consulting Reserve Auditors.** Consulting Reserve Estimators and consulting Reserve Auditors, or any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners or employees, should be independent from any Entity with respect to which such Reserve Estimators, Reserve Auditors or consulting firm estimate or audit Reserve Information which purports to have been estimated or audited in accordance with these Standards.

4.3 Standards of Independence for Consulting Reserve Estimators and Consulting Reserve Auditors.[3] Consulting Reserve Estimators and consulting Reserve Auditors, and any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners or employees, would not normally be considered independent with respect to an Entity if, during the term of their professional engagement, such Reserve Estimators, Reserve Auditors or consulting firm

(a) Investments. Either owned or acquired, or were committed to acquire, directly or indirectly, any material financial interest in (i) such Entity or any corporation or other person affiliated therewith or (ii) any property with respect to which Reserve Information is to be estimated or audited;

(b) Joint Business Venture. Either owned or acquired, or were committed to acquire, directly or indirectly, any material joint business investment with such Entity or any officer, director, principal stockholder or other person affiliated therewith;

(c) Borrowings. Were indebted to such Entity or any officer, director, principal stockholder or other person affiliated therewith; provided, however, that retainers, advances against work-in-process and trade accounts payable arising from the purchase of goods and services in the ordinary course of business shall not constitute indebtedness within the meaning of this Section 4.3(c);

(d) Guarantees of Borrowings. Were indebted to any individual, corporation or other person under circumstances where the payment of such indebtedness was guaranteed by such Entity or any officer, director, principal stockholder or other person affiliated therewith;

(e) Loans to Clients. Extended credit to (i) such Entity or any officer, director, principal stockholder or other person affiliated therewith or (ii) any person having a material interest in any property with respect to which Reserve Information was estimated or audited; provided, however, that trade accounts receivable arising in the ordinary course of business from the performance of petroleum engineering and related services shall not constitute the extension of credit within the meaning of this Section 4.3(e);

(f) Guarantees for Clients. Guaranteed any indebtedness (i) owed by such Entity or any officer, director, principal stockholder or other person affiliated therewith or (ii) payable to any individual, corporation, entity or other person having a material interest in the Reserve Information pertaining to such Entity;

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[3] For purposes of this Section 4.3, the term "affiliated" shall, with respect to an Entity, describe the relationship of a person to such Entity under circumstances in which such person, directly or indirectly through one or more intermediaries, controls or is controlled by or is under common control with such Entity; provided, however, that commercial banks and other bona fide financial institutions shall not be considered to be affiliated with the Entity to which the Reserve Information relates unless such banks or institutions actively participate in the management of the properties of such Entity.

Unless the context requires otherwise, the term "material" shall, for purposes of this Section 4.3, be interpreted with reference to the net worth of the consulting Reserve Estimators or the consulting Reserve Auditors, or any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners or employees.

(g) Purchases and Sales of Assets. Purchased any material asset from, or sold any material asset to, such Entity or any officer, director, principal stockholder or other person affiliated therewith;

(h) Certain Relationships With Client. Were directly or indirectly connected with such Entity as a promoter, underwriter, officer, director or principal stockholder, or in any capacity equivalent thereto, or were otherwise not separate and independent from the operating and investment decision-making process of such Entity;

(i) Trusts and Estates. Were trustees of any trust, or executors or administrators of any estate, if such trust or estate had any direct or indirect interest material to it in such Entity or in any property with respect to which Reserve Information was estimated or audited; or

(j) Contingent Fee. Were engaged by such Entity to estimate or audit Reserve Information pursuant to any agreement, arrangement or understanding whereby the remuneration or fee paid by such Entity was contingent upon, or related to, the results or conclusions reached in estimating or auditing such Reserve Information.

The independence of consulting Reserve Estimators and consulting Reserve Auditors, and the independence of any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners or employees, shall not be considered impaired merely because other petroleum engineering and related services were performed (i) for such Entity or any officer, director, principal stockholder or other person affiliated therewith or (ii) in regard to any property with respect to which Reserve Information was estimated or audited; provided, however, such other services must have been of a type normally rendered by the petroleum engineering profession.

4.4 Requirement of Objectivity for Reserve Auditors Internally Employed by Entities. Reserve Auditors who are internally employed by an Entity should be objective with respect to such Entity if such Reserve Auditors audit Reserve Information relating to such Entity which purports to have been estimated or audited in accordance with these Standards.

4.5 Standards of Objectivity for Reserve Auditors Internally Employed by Entities. Reserve Auditors internally employed by an Entity would normally be considered to be in a position of objectivity with respect to such Entity if, during the time period in which Reserve Information was audited, such Reserve Auditors

(a) Accountability to Management. Were assigned to a staff group which was (i) accountable to upper level management of such Entity and (ii) separate and independent from the operating and investment decision-making process of such Entity; and

(b) Freedom to Report Irregularities. Were granted complete and unrestricted freedom to report, to the principal executives and board of directors of such entity, any substantive or procedural irregularities of which such Reserve Auditors became aware during their audit of Reserve Information pertaining to such Entity.

4.6 Requirement of Confidentiality. Reserve Estimators and Reserve Auditors, and any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners or employees should retain in strictest confidence Reserve Information and other data and information furnished by, or pertaining to, an Entity, and such Reserve Information, data and information should not be disclosed to others without the prior consent of such Entity.

Article V—Standards for Estimating Proved Reserves and Other Reserve Information

5.1 General Considerations in Estimating Reserve Information. Reserve Information may be estimated through the use of generally accepted geologic and engineering methods that are consistent with both these Standards and any statutory and regulatory provisions which are applicable to such Reserve Information in accordance with its intended use. In estimating Reserve Information for a property or group of properties, Reserve Estimators will determine the geologic and engineering methods to be used in estimating Reserve Information by considering (i) the sufficiency and reliability of the data base; (ii) the stage of development; (iii) the performance history; (iv) their experience with respect to such property or group of properties, and with respect to similar properties; and (v) the significance of such property or group of properties to the aggregate oil and gas properties and interests being estimated or evaluated. The report as to Reserve Information should set forth information regarding the manner in which, and the assumptions pursuant to which, such report was prepared. Such disclosure should include, where appropriate, definitions of the significant terms used in such report, the geologic and engineering methods and measurement base used in preparing the Reserve Information and the source of the data used with regard to ownership interests, oil and gas production and other performance data, costs of operation and development, product prices, and agreements relating to current and future operations and sales of production.

5.2 Adequacy of Data Base in Estimating Reserve Information. The sufficiency and reliability of the data base is of primary importance in the estimation of proved reserves and other Reserve Information. The type and extent of the data required will necessarily vary in accordance with the methods employed to estimate proved reserves and other Reserve Information. In this regard, information must be available with respect to each property or group of properties as to operating interests, expense interests and revenue interests and future changes in any of such interests that, based on current circumstances, are expected to occur. Additionally, if future net revenue from proved reserves, or the present value of such future net revenue, is to be estimated, the data base should include, with respect to each property or group of properties, costs of operation and development, if available, product prices and a description of any agreements relating to current and future operations and sales of production.

5.3 Estimating Proved Reserves. The acceptable methods for estimating proved reserves include (i) the volumetric method; (ii) evaluation of the performance history, which evaluation may include an analysis and projection of producing ranges, reservoir pressures, oil-water ratios, gas-oil ratios and gas-liquid ratios; (iii) development of a mathematical model through consideration of material balance and computer simulation techniques; (iv) analogy to other reservoirs if geographic location, formation characteristics or similar factors render such analogy appropriate. In estimating proved reserves, Reserve Estimators should utilize the particular methods, and the number of methods, which in their professional judgment are most appropriate given (i) the geographic location, formation characteristics and nature of the property or group of properties with respect to which proved reserves are being estimated; (ii) the amount and quality of available data; and (iii) the significance of such property or group of properties in relation to the oil and gas properties with respect to which proved reserves are being estimated.

5.4 Estimating Proved Reserves by the Volumetric Method. Estimating proved reserves in accordance with the volumetric method involves estimation of oil in place based upon review and analysis of such documents and information as (i) ownership and development maps; (ii) geologic maps; (iii) electric logs and formation tests; (iv) relevant reservoir and core data; and (v) information regarding the completion of oil and gas wells and any production performance thereof. An appropriate estimated recovery factor is applied to the resulting oil in place figure in order to derive estimated proved reserves.

5.5 Estimating Proved Reserves by Analyzing Performance Data. For reservoirs with respect to which performance has disclosed reliable production trends, proved reserves may be estimated by analysis of performance histories and projections of such trends. These estimates may be primarily predicated on an analysis of the rates of decline in production and on appropriate considerations of other performance parameters such as reservoir pressures, oil-water ratios, gas-oil ratios and gas-liquid ratios.

5.6 Estimating Proved Reserves by Using Mathematical Models. Proved reserves and future production performance can be estimated through a combination of detailed geologic and reservoir engineering studies and mathematical or computer simulation models. The validity of the mathematical simulation models is enhanced by the degree to which the calculated history matches the performance history. Where performance history is unavailable, special consideration should be given to determining the sensitivity of the calculated ultimate recoveries to the data that is the most uncertain. After making such sensitivity determination, the proved ultimate recovery should be based on the selection of the most likely data encompassed within the ranges of their uncertainty.

5.7 Estimating Proved Reserves by Analogy to Comparable Reservoirs. If performance trends have not been established with respect to oil and gas production, future production rates and proved reserves may be estimated by analogy to reservoirs in the same geographic area having similar characteristics and established performance trends. Where appropriate, proved reserves may be estimated using multiples of current rates of production.

5.8 Estimated Future Rates of Production. Future rates of oil and gas production may be estimated by extrapolating production trends where such have been established. If production trends have not been established, future rates of production may be estimated by analogy to the respective rates of production of reservoirs in the same geographic area having similar geologic features, reservoir rock and fluid characteristics. If there is not available either (i) production trends from the property or group of properties with respect to which proved reserves are being estimated or (ii) rates of production from similar reservoirs, the estimation of future rates of production may be predicated on an assumed future decline rate that takes into proper consideration the cumulative oil and gas production that is estimated to occur prior to the predicted decline in such production in relation to the estimated ultimate production. Reservoir simulation is also an accepted method of estimating future rates of production. Irrespective of the method used, however, proper consideration should be given to (i) the producing capacities of the wells; (ii) the number of wells to be drilled in the future, together with the proposed times when such are to be drilled and the structural positions of such wells; (iii) the energy inherent in, or introduced to, the reservoir; (iv) the estimated ultimate recovery; (v) future remedial work to be performed; (vi) the scheduling of future well abandonments; (vii) normal downtime which may be anticipated; and (viii) artificial restriction of future producing rates that is attributable to statutory and regulatory provisions, purchaser proration and other factors.

5.9 Estimating Reserve Information Other Than Proved Reserves and Future Rates of Production. A Reserve Estimator often estimates Reserve Information other than proved reserves and future rates of production in order to make his or her report more useful. Proved reserves net to the interests appraised are estimated using the Entity's net interest in the property or group of properties, or in the production therefrom, with respect to which proved reserves were estimated. The nature of the net interest of the Entity may be established or affected by any number of arrangements which the Reserve Estimator must take into account. Estimated future revenues are calculated from the estimated future rates of production by applying the appropriate sales prices furnished by the Entity or by using such other data as may be required by statutory and regulatory provisions that are applicable to such report in accordance with its intended use. Where appropriate, the Reserve Estimator deducts from such future revenues items such as (i) any existing production or severance taxes, (ii) taxes levied against property or production, (iii) estimates of future operating costs and (iv) estimates of any future development, equipment or other significant capital expenditures required for the production of the proved reserves. Such deductions normally include various overhead and management charges. For some purposes, it is desirable to subtract income taxes and other governmental levies in estimating future net revenues.

In estimating future net revenues, the Reserve Estimator should consider, where appropriate, any likely changes (i) from historical operating costs, (ii) from current estimates of future capital expenditures and (iii) in other factors which may affect estimated limits of economic production.

Article VI—Standards for Auditing Proved Reserves and Other Reserve Information

6.1 The Concept of Auditing Proved Reserves and Other Reserve Information. An audit is an examination of Reserve Information that is conducted for the purpose of expressing an opinion as to whether such Reserve Information, in the aggregate, is reasonable and has been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

As discussed in Section 1.3, the estimation of proved reserves and other Reserve Information is an imprecise science due to the many unknown geologic and reservoir factors that can only be estimated through sampling techniques. Since proved reserves are therefore only estimates, such cannot be audited for the purpose of verifying exactness. Instead, Reserve Information is audited for the purpose of reviewing in sufficient detail the policies, procedures and methods used by an Entity in estimating its Reserve Information so that the Reserve Auditors may express an opinion as to whether, in the aggregate, the Reserve Information furnished by such Entity is reasonable and has been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

The methods and procedures used by an Entity, and the Reserve Information it furnishes, must be reviewed in sufficient detail to permit the Reserve Auditor, in his or her professional judgment, to express an opinion as to the reasonableness of such Entity's Reserve Information. In some cases the auditing procedure may require independent estimates of Reserve Information for particular properties. The desirability of such reestimation will be determined by the Reserve Auditor exercising his or her professional judgment in arriving at an opinion as to the reasonableness of the Entity's Reserve Information.

6.2 Limitations on Responsibility of Reserve Auditors. Since the primary responsibility for estimating and presenting Reserve Information pertaining to an Entity is with the management of such Entity, the responsibility of Reserve Auditors is necessarily limited to any opinion they express with respect to such Reserve Information. In discharging such responsibility, Reserve Auditors may accept, generally without independent verification, information and data furnished by the Entity with respect to ownership interests, oil and gas production, historical costs of operation and development, product prices, agreements relating to current and future operations and sales of production, and other specified matters. If during the course of the audit, however, questions arise as to the accuracy or sufficiency of any information or data furnished by the Entity, the Reserve Auditor should not rely on such information or data unless such questions are resolved or the information or data is independently verified. If Reserve Information is used for financial accounting purposes, certain basic data would ordinarily be tested by an Entity's independent public accountants in connection with their examination of the Entity's financial statements. Such basic data would include information such as the property interests owned by the Entity, historical production data and the prices, costs and discount factors used in valuations of proved reserves. Reserve Auditors should, however, review estimates of major expenditures for development and equipment and any major differences between historical operating costs and estimated future operating costs.

6.3 Understanding Among an Entity, Its Independent Public Accountants and the Reserve Auditors. An understanding should exist among an Entity, its independent public accountants and the Reserve Auditors with respect to the nature of the work to be performed by the Reserve Auditors. Irrespective of whether the Reserve Auditors are consultants or internally employed by the Entity, the understanding between the Entity and the Reserve Auditors should include at least the following:

(a) Availability of Reserve Information. The Entity will provide the Reserve Auditors with (i) all Reserve Information prepared by such Entity, (ii) access to all basic data and documentation pertaining to the oil and gas properties of such Entity, and (iii) access to all personnel of such Entity who might have information relevant to the audit of such Reserve Information.

(b) Performance of Audit. The Reserve Auditors will (i) study and evaluate the methods and procedures used by the Entity in estimating and documenting its Reserve Information; (ii) review the reserve definitions and classifications used by such Entity; (iii) test and evaluate the Reserve Information of such Entity to the extent considered necessary by the Reserve Auditors; and (iv) express an opinion as to the reasonableness, in the aggregate, of such Entity's Reserve Information.

(c) Availability of Audit Report to Independent Public Accountants. The Reserve Auditors will (i) permit their audit report to be provided to the inde-

pendent public accountants of the Entity for use in their examination of its financial statements and (ii) be available to discuss their audit report with such independent public accounts.

(d) Coordination Between Reserve Auditors and Independent Public Accountants. The Reserve Auditors and the Entity's independent public accountants will coordinate their efforts and agree on the records and data of the Entity to be reviewed by each.

In the case of an audit to be conducted by consulting Reserve Auditors, it is preferable that such understanding be documented, such as through an engagement letter between the Entity and the consulting Reserve Auditors.

6.4 Procedures for Auditing Reserve Information. Irrespective of whether the Reserve Information pertaining to an Entity is being audited by consulting Reserve Auditors or Reserve Auditors internally employed by such Entity, the audit should be conducted in accordance with the following procedures:

(a) Proper Planning and Supervision. The audit should be adequately planned and assistants, if any, should be properly supervised.

(b) Early Appointment of Reserve Auditors. Where appropriate, early appointment of Reserve Auditors is advantageous to both the Entity and the Reserve Auditors. Early appointment enables the Reserve Auditors to plan their work so that it may be done expeditiously and to determine the extent to which such can be completed prior to the balance sheet date. Preliminary work by the Reserve Auditors benefits the Entity by facilitating the efficient and expeditious completion of the audit of such Entity's Reserve Information.

(c) Disclosure of the Possibility of a Qualified Audit Opinion. Before accepting an engagement, Reserve Auditors should ascertain whether circumstances are likely to permit an unqualified opinion with respect to an Entity's Reserve Information and, if such will not, they should discuss with such Entity (i) the possible necessity of their rendering a qualified opinion and (ii) the possible remedies to the circumstances giving rise to the potential qualification of such opinion.

(d) Interim Audit Procedures. Many audit tests can be conducted at almost any time during the year. In the course of interim work, the Reserve Auditors make tests of the Entity's methods, procedures and controls to determine the extent to which such are reliable. It is acceptable practice for the Reserve Auditors to complete substantial parts of an audit examination at interim dates.

When a significant part of an audit is completed during the year and the Entity's methods, procedures and controls are found to be effective, the year-end audit procedure may primarily consist of an evaluation of the impact of new data. The Reserve Auditors must nevertheless be satisfied that the procedures and controls are still effective at the year-end and that new discoveries, recent oil and gas production and other recent information and data have been taken into account. Reserve Auditors would not be required to retest the data base pertaining to an Entity's properties and interests unless their inquiries and observations indicate that conditions have changed significantly.

(e) General Matters to Be Reviewed With Respect to Reserve Information. An audit of the Reserve Information pertaining to an Entity should include a review of (i) the policies, procedures, documentation and guidelines of such

Entity with respect to the estimation, review and approval of its Reserve Information; (ii) the qualifications of Reserve Estimators internally employed by such Entity; (iii) ratios of such Entity's proved reserves to annual production for, respectively, oil, gas and natural gas liquids; (iv) historical reserve and revision trends with respect to the oil and gas properties and interests of such Entity; (v) the ranking by size of properties or groups of properties with respect to estimates of proved reserves or the future net revenue from such proved reserves; (vi) the percentages of proved reserves estimated by each of the various methods set forth in Section 5.3 for estimating proved reserves; and (vii) the significant changes occurring in such Entity's proved reserves, other than from production, during the year with respect to which the audit is being prepared.

(f) Evaluation of Internal Policies, Procedures and Documentation. Reserve Auditors should review and evaluate the internal policies, procedures and documentation of an Entity to establish a basis for reliance thereon in determining the nature, extent and timing of the audit tests to be applied in the examination of such Entity's Reserve Information and other data and matters. The internal policies, procedures and documentation to be reviewed with respect to an Entity should include (i) reserve definitions and classifications used by such Entity; (ii) such Entity's policies pertaining to, and management involvement in, the review and approval of Reserve Information and changes therein; (iii) the frequency with which such Entity reviews existing Reserve Information; (iv) the form, content and documentation of the Reserve Information of such Entity, together with such Entity's internal distribution thereof; and (v) the flow of data to and from such Entity's reserve inventory system.

(g) Testing for Compliance. Reserve Auditors should conduct tests and spot checks to confirm that (i) there is adherence on the part of an Entity's internal Reserve Estimators and other employees to the policies and procedures established by such Entity; and (ii) the data flowing into the reserve inventory system of such Entity is complete and consistent with other available records.

(h) Substantive Testing. In conducting substantive tests, Reserve Auditors should give priority to each property or group of properties of an Entity having (i) a large reserve value in relation to the aggregate properties of such Entity; (ii) a relatively large reserve value and major changes during the audit year in the Reserve Information pertaining to such property or group of properties; and (iii) a relatively large reserve value and a high degree of uncertainty in the Reserve Information pertaining thereto. The amount of substantive testing performed with respect to particular Reserve Information of an Entity should depend on the assessment of (i) the general degree of uncertainty with respect to such Reserve Information, (ii) the evaluation of the internal policies, procedures and documentation of such Entity and (iii) the results of the compliance testing with respect to such Entity. Such substantive testing could therefore appropriately range from a limited number of tests to the complete estimation of Reserve Information with respect to a majority of an Entity's reserves.

6.5 Records and Documentation With Respect to Audit. Reserve Auditors should document, and maintain records with respect to, each audit of the Reserve Information of an Entity. Such documentation and records should include, among other things, a description of (i) the Reserve Information audited: (ii) the review and evaluation of such Entity's policies, procedures and documentation; (iii) the compliance testing performed with respect to such Entity; and (iv) the substantive tests performed in the course of such audit.

6.6 Forms of Unqualified Audit Opinions. Acceptable forms of unqualified audit opinions for consulting Reserve Auditors and Reserve Auditors internally employed by Entities are attached to these Standards as, respectively, Exhibits "A" and "B."

Exhibit "A"—Illustrative Unqualified Audit Opinion of Consulting Reserve Auditor*

[Date]

Entity
[Address]
Independent Public Accountants of Entity
[Address]

Gentlemen:

At your request, we have examined the estimates as of [dates] set forth in the accompanying table with respect to (i) the proved reserves of Entity, (ii) changes in such proved reserves during the period indicated, (iii) the future net revenue from such proved reserves, and (iv) the present value of such future net revenue. Our examination included such tests and procedures as we considered necessary under the circumstances to render the opinion set forth herein.

[A detailed description of the audit should be set forth.]

We are independent with respect to Entity as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers.

It should be understood that our above-described audit does not constitute a complete reserve study of the oil and gas properties of Entity. In the conduct of our report, we have not independently verified the accuracy and completeness of information and data furnished by Entity with respect to ownership interests, oil and gas production, historical costs of operation and development, product prices, agreements relating to current and future operations and sales of production, and [specify other information, data and matters upon which reliance was placed]. We have, however, specifically identified to you the information and data upon which we so relied so that you may subject such to those procedures that you consider necessary. Furthermore, if, in the course of our examination, something came to our attention which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

Please be advised that, based upon the foregoing, in our opinion the above-described estimates of Entity's proved reserves and other Reserve Information are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers.

[Insert, where appropriate and to the extent warranted by the Reserve Auditor's examination, whether the Reserve Information is in conformity with specified governmental regulations.]

[Optional: This letter is solely for the information of Entity and for the information and assistance of its independent public accountants in connection

* If a Reserve Auditor is unable to give an unqualified opinion as to an Entity's Reserve Information, the Reserve Auditor should set forth in his or her opinion the nature and extent of the qualifications to such opinion and the reasons therefor.

with their review of, and report upon, the financial statements of Entity. This letter should not be used, circulated or quoted for any other purpose without the express written consent of the undersigned or except as required by law.]

Very truly yours,

RESERVE AUDITOR

By____________

Exhibit "B"—Illustrative Unqualified Audit Opinion of Reserve Auditor Internally Employed by an Entity*

[Date]

Entity
[Address]
Independent Public Accountants of Entity
[Address]

Gentlemen:

I have examined the estimates as of [dates] set forth in the accompanying table with respect to (i) the proved reserves of Entity, (ii) changes in such proved reserves during the period indicated, (iii) the future net revenue from such proved reserves, and (iv) the present value of such future net revenue. My examination included such tests and procedures as I considered necessary under the circumstances to render the opinion set forth herein.

[A detailed description of the audit tests and procedures may be set forth.]

I meet the requirements of objectivity for Reserve Auditors internally employed by Entities as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers.

It should be understood that my above-described audit does not constitute a complete reserve study of the oil and gas properties of Entity. In the conduct of my report, I have not independently verified the accuracy and completeness of information and data furnished by other employees of Entity with respect to ownership interests, oil and gas production, historical costs of operation and development, development, product prices, agreements relating to current and future operations and sales of production, and [specify other information, data and matters upon which reliance was placed]. I have, however, specifically identified to you the information and data upon which I so relied so that you may subject such to those procedures that you consider necessary. Furthermore, if, in the course of my examination, something came to my attention which brought into question the validity or sufficiency of any of such information or data, I did not rely on such information or data until I had satisfactorily resolved my questions relating thereto or independently verified such information or data.

Please be advised that, based upon the foregoing, in my opinion the above-described estimates of Entity's proved reserves and other Reserve Information are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers.

[Insert, where appropriate and to the extent warranted by the Reserve Auditor's examination, whether the Reserve Information is in conformity with specified governmental regulations.]

Very truly yours,
RESERVE AUDITOR
By____________

* If a Reserve Auditor is unable to give an unqualified opinion as to an Entity's Reserve Information, the Reserve Auditor should set forth in his or her opinion the nature and extent of the qualifications to such opinion and the reasons therefor.

Appendix C
Information Sources

Further information on matters addressed in this Guide is available through various publications and services listed in the table that follows. Many non-government and some government publications and services involve a charge or membership requirement.

Fax services allow users to follow voice cues and request that selected documents be sent by fax machine. Some fax services require the user to call from the handset of the fax machine, others allow the user to call from any phone. Most fax services offer an index document, which lists titles and other information describing available documents.

Electronic bulletin board services allow users to read, copy, and exchange information electronically. Most are available using a modem and standard communications software. Some bulletin board services are also available using one or more Internet protocols.

Recorded announcements allow users to listen to announcements about a variety of recent or scheduled actions or meetings.

All telephone numbers listed are voice lines, unless otherwise designated as fax (f) or data (d) lines. Required modem speeds, expressed in bauds per second (bps), are listed for data lines.

Information Sources

Organization	General Information	Fax Services	Internet Web Site	Recorded Announcements
American Institute of Certified Public Accountants (AICPA)	*Order Department* Harborside Financial Center 201 Plaza Three Jersey City, NJ 07311-3881 (888) 777-7077 Copies of AICPA publications referred to in this document may be obtained by calling the AICPA Order Department (888) 777-7077	*24 Hour Fax Hotline* (201) 938-3787	http://www.aicpa.org	
Financial Accounting Standards Board (FASB)	*Order Department* P.O. Box 5116 Norwalk, CT 06856-5116 (203) 847-0700, ext. 10 Action Alert Telephone Line (203) 847-0700, ext. 444 Copies of FASB publications referred to in this document may be obtained directly from the FASB by calling the FASB Order Department.		http://www.fasb.org	*Action Alert Telephone Line* (203) 847-0700 (ext. 444)
U.S. Securities and Exchange Commission (SEC)	*Publications Unit* 450 Fifth Street, NW Washington, DC 20549-0001 (202) 942-4046 *SEC Public Reference Room* (202) 942-8097	*Information Line* (202) 942-8088, ext. 4 (202) 942-7114 (tty)	http://www.sec.gov	*Information Line* (202) 942-8088 (202) 942-7114 (tty)

Organization	General Information	Fax Services	Internet Web Site	Recorded Announcements
Institute of Petroleum Accounting	University of North Texas P.O. Box 305460 Denton, Texas 76203-6677	*General Information* (940) 565-3170 Fax (940) 369-8839	http://www.unt.edu/ipa	
American Petroleum Institute	1220 L Street NW Washington, DC 20005 Publications and Materials (202) 682-8375	*General Information* (202) 682-8000	http://www.api.org	
Gas Research Institute	8600 W. Bryn Mawr Chicago, IL 60631	*General Information* (773) 399-8100	http://www.gri.org	

Appendix D

Schedule of Changes Made to Audits of Entities With Oil and Gas Producing Activities

Reference	Change	Date
General	The term "examination" has been changed to "audit" to conform to the terminology used in SAS No. 58.	October, 1990
Preface	Conformed to the terminology used in SAS No. 78.	April, 1997
Paragraph 1.52 (footnote 2)	Reference to SAS No. 45 changed to SAS No. 52.	October, 1990
Paragraphs 1.55, 1.56, and 1.57	Added.	June, 1996
Paragraph 2.116	Revised to reflect the issuance of SEC Financial Reporting Release 40A.	May, 1993
Paragraph 2.132	Added.	June, 1996
Paragraph 2.132 (footnote *)	Added to reflect the issuance of FASB Statement No. 133.	May, 1999
Paragraph 2.133	Added.	June, 1996
Paragraph 2.134	Added to reflect the issuance of FASB Statement No. 133.	May, 1999
Chapter 3 (footnote*)	Added to refer readers to the Internal Revenue Code.	April, 1998
Paragraphs 3.12 and 3.13	Conformed to the terminology used in FASB Statement No. 109.	June, 1996
Chapter 4	Conformed to the terminology used in SAS No. 78.	April, 1997
Paragraph 5.08	Conformed to the terminology used in SAS No. 78.	April, 1997
Paragraph 5.16	Conformed to the terminology used in SAS No. 78.	April, 1997
Paragraph 5.20	Reference to SAS No. 45 changed to auditing interpretation No. 1 of SAS No. 52.	October, 1990
Paragraph 5.20	Reference to SAS No. 11 changed to SAS No. 73; Note reference to the supersession of SAS No. 11 deleted.	May, 1995
Paragraphs 5.22 and 5.23	Added to reflect the issuance of SAS No. 83; Subsequent paragraphs renumbered.	April, 1998
Renumbered paragraph 5.33	Conformed to the terminology used in SAS No. 78.	April, 1997
Paragraph 5.33 (footnote*)	Added to reflect the issuance of SAS No. 85.	April, 1998

Reference	Change	Date
Renumbered paragraph 5.41	Revised to reflect the issuance of FASB Statement No. 121.	June, 1996
Renumbered paragraph 5.59	Conformed to the terminology used in SAS No. 56.	April, 1992
Renumbered paragraph 5.70	Conformed to the terminology used in SAS No. 78.	April, 1997
Renumbered paragraphs 5.73 and 5.75	Reference to SAS No. 27 and SAS No. 45 changed to SAS No. 52 and auditing interpretation No. 1 of SAS No. 52.	October, 1990
Appendix A	Introduction modified; Auditor's report added.	June, 1996
Appendix A	Exhibits revised to reflect the issuance of recent authoritative literature.	April, 1998
Appendix A (Exhibit D, footnotes)	Added or revised to reflect the issuance of FASB Statement No. 133.	May, 1999

Glossary

AFE. Authorization for expenditure.

barrel. A standard measurement in the oil industry. One barrel equals 42 U.S. gallons. On the average, 7.33 barrels of crude oil weigh one metric ton; 7.5 barrels weigh one long ton; and 6.65 barrels weigh one short ton.

bottom hole contribution. A defined cash contribution by a noninterest owner to the working interest owners upon the drilling of a well, regardless of the outcome, to a specific geological formation or to a specified depth.

carried interest. An arrangement in which one party agrees to develop and operate a property at its cost but with the right to recapture its costs or a defined greater amount from the proceeds of production.

casing. Heavy steel pipe that lines the hole of a well. Initially, casing is used near the surface and is cemented into place to guide the drill pipe. Later, if oil or gas is found, production casing is set near the bottom of the hole. Surface casings protect any fresh water supplies from contamination during drilling operations. Lower casings keep loose earth, rock, salt water, and other material out of the well, protect the producing reservoir, and serve as conduits for the tubing that brings oil and gas to the surface.

casing point. The point at which the operator decides whether or not it will be profitable enough to set production casing and complete the well.

completion. The process of attempting to bring an oil or gas well into production. The process begins only after the well has reached the depth where oil or gas is thought to exist and generally involves cleaning out the material the drill bit has ground up. Casing is run to protect the producing formation. Completion also may include perforating the casing so the oil or gas can flow into the well. Sometimes the flow rate can be improved by an acid treatment or by fracturing the oil formation to open channels for the oil to flow into the well.

condensate. A mixture of liquid hydrocarbons at atmospheric (surface) conditions that occur as a vapor in underground gas reservoirs. The liquids (condensate) are separated from the gas in field separators or gas processing plants. These liquids generally include propane, butane, and heavier hydrocarbons used in making gasoline.

condition value. The application of a percentage of replacement cost for new materials to used equipment at the time when taken out of service.

coring. A technique for cutting samples of subsurface rocks as a well is being drilled. A hollow bit or cutting tool at the bottom of the drill pipe cuts a cylindrical length of rock, or core, as the drill pipe rotates. The core is pushed up into a hollow tube, or core barrel, attached to the bit. The core barrel is brought to the surface and the core sample removed for study. The average core is about 30 feet long.

crude oil. Liquid petroleum that has not been refined. Sour crude oils have relatively large amounts of sulfur (1 percent or more). Sweet crudes have less sulfur and are more valuable. Most U.S. crudes tend to be sweet, while Middle East crudes tend to be sour. Crude oil is generally sold on a volume basis. The volume is corrected for any basic sediment and water (BS&W) present and adjusted to the standard base temperature of 60 degrees Fahrenheit. Light crude oils have a lower specific gravity than do heavy crudes, which may be thick and viscous.

DD&A. Depreciation, depletion, and amortization.

delay rental. Payments to the lessor for the privilege of delaying drilling on a lease for a period of time, usually one year.

development well. A well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

division order. A legal document signed by each owner of a revenue interest specifying the percent ownership of each owner.

dry hole. A well that either finds no oil or gas or finds too little to make it financially worthwhile to produce.

dry hole contribution. A defined cash contribution by a noninterest owner to the working interest owners, payable only if the well is unsuccessful.

exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well.

farm-out. A sharing of oil or gas exploration activities and costs. A company with the right to explore more potential acreage than it can or wishes to handle may invite others to explore portions of the tract in return for a share of whatever oil or gas is found.

fracturing. A method of increasing the flow of oil or gas into a well. Production of individual wells often decreases because the underground formation is not sufficiently permeable to allow the oil to move freely toward the well.

free wells. An assignment of an individual fraction of the working interest to a second party in consideration for an undertaking by the second party to drill and equip a well at no cost to the first party.

G&G. Geological and geophysical.

improved recovery. "Man made" methods as opposed to "natural" methods of increasing the flow of oil or gas from underground reservoirs.

injection well. A well that is used to pump water, gas, or chemicals into the underground reservoir of a producing field. The object is to maintain the pressure needed to drive oil and gas to the surface or to sweep more oil out of the reservoir. Sometimes the salt water produced with oil is pumped back into the reservoir. This serves two purposes: It helps to extend the life of the oil field, and it gets rid of a potential pollutant.

intangible drilling costs (IDC). Expenses for labor, fuel, repair, hauling, rig rental, and supplies used in the drilling of a well. These expenses differ from the cost of "tangibles," which include anything that has inherent salvage value.

joint interest billings (JIB). The process of the operator's billing costs of joint exploration, development, and operations to the various working interest owners.

joint interests. Ownership of individual fractions or percentages of the working interests held by two or more parties.

lease bonus. The initial consideration paid by the lessee to the lessor to acquire the mineral rights.

LOE. Lease operating expenses.

mcf. Thousand cubic feet. The standard volume measure of natural gas at a standard pressure and temperature.

natural gas. Consists largely of the hydrocarbon methane. It is found in underground formations either by itself or with crude oil. It is the cleanest burning of all fossil fuels. Once virtually a waste product, natural gas provides about one-third of the total energy used in the United States.

net profits interest. An interest that entitles the owner to a specified share of net profits from production of hydrocarbons.

overriding royalty. An interest in production similar to a royalty. It differs from a royalty, however, in that it is created out of the working interest.

payout. The defined point in many drilling arrangements and partnerships at which one party has recovered its costs and revenue sharing may change.

percentage depletion. A provision of the U.S. income tax law that applies to producers of some seventy-five minerals, including some oil and gas producers. The U.S. income tax law allows a mineral producer a percentage depletion deduction based on the gross income from mineral properties.

pooled interests. The combination of two or more working and nonoperating interests in several properties to form a new economic unit.

posted prices. In the petroleum industry, the "price lists" posted for various types of crude by the buyer in the United States, and the seller in foreign countries.

production payments. A nonoperating interest payable from a specific portion of production expressed either as a certain amount of money (with or without interest) or a certain number of units of hydrocarbons.

proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

proved reserves. The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economics and operating conditions.

proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

recompletions. Work-overs that entail completion of the well in a productive structure, either shallower or deeper, that has not previously been produced through the well.

reserves. Defined as proved, probable, and possible and as developed or undeveloped.

reservoir. An underground formation where oil or gas has accumulated. The formation consists of porous rock that holds droplets of oil and gas. If the rock pores are interconnected to allow oil or gas to move through it, it is called permeable rock.

revenue interest. The interest of each owner of an economic interest in production of hydrocarbons from a specified property. The revenue interest normally differs from the percentage working interest because of nonworking interests in each property.

reversionary interest. A revenue interest that increases upon the attainment of certain specified objectives, often at payout.

royalty. The right to a share of production retained by the lessor free and clear of exploration, development, and operating costs.

stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells are customarily drilled without the intention of being completed for production.

tangible equipment. Equipment such as casing, tubing, pumps, tanks, and other equipment installed on a well.

top leasing. The practice of obtaining a new lease on a property prior to the expiration of the existing lease. The new lease becomes effective at the expiration of the old lease.

work-over. Major remedial operations required to maintain or increase production rates. *See* recompletions.

Bibliography

Books—Accounting and Reporting

American Institute of Certified Public Accountants. *Financial Reporting in the Extractive Industries.* Accounting Research Study No. 11. New York: AICPA, 1969.

A research study sponsored by the Accounting Principles Board in its effort to develop oil and gas accounting standards.

Baggett, Monte R.; Dole, Richard D.; and Short, Jack E. *Anatomy of a Drilling Fund.* Dallas: Coopers and Lybrand, 1980.

Discusses aspects that the investor, sponsor, and accountant involved in a drilling fund must consider, with an emphasis on tax aspects.

Brock, Horace R.; Jones, Donald M.; and Klingstedt, John P. *Accounting for Oil and Gas Producing Companies, Part 1: Exploration, Acquisition, Development and Production.* Denton, Texas: Professional Development Institute, North Texas State University, 1981.

Serves as a practical reference guide on financial accounting and reporting for oil and gas producing companies. Covers the following: the economic aspects of the industry; company organization; general principles of oil and gas accounting; accounting for expenditures incurred in exploration, leasing, and development activities; revenue accounting; and accounting for lifting costs. Emphasizes the successful efforts method of accounting.

________. *Accounting for Oil and Gas Producing Companies, Part 2: Amortization, Full Costing and Disclosures.* Denton, Texas: Professional Development Institute, North Texas State University, 1982.

A continuation of Part 1 above. Topics covered include the following: depreciation, depletion, and amortization; the full cost method; sales and subleases; production payments; poolings of capital; deferred income taxes; supplemental disclosures; joint operations; gas production.

Burke, Kenneth M., and Durand, Francis L. *Oil and Gas Limited Partnerships, Accounting, Reporting and Taxation.* Denton, Texas: Professional Development Institute, North Texas State University, 1984.

Topics include federal income tax, windfall profit tax, and accounting and reporting matters. Illustrates several different types of limited partnerships. Exhibits include detailed computations of taxable income distribution, investor cash flow, depreciation, depletion and amortization, windfall profit tax, allowable depletion, tax liability, and deferred taxes.

Cox, David B. *Energy Resources Tax Reports.* Chicago: Commerce Clearing House, Inc., 1984.

Two-volume publication covering oil and gas taxation. Revised annually.

Crumbley, D. Larry, and Grossman, Steven D., eds. *Readings in Oil Industry Accounting.* Tulsa: Petroleum Publishing Company, 1980.

Articles are grouped in five subject areas of interest to the petroleum industry. Areas covered are the following: full cost, successful efforts, and discovery value; FASB and SEC releases; empirical studies; profitability in the oil industry; and accounting for inflation.

Koester, Robert J. *Handbook on Oil and Gas Accounting.* Oklahoma City: Institute for Energy Development, 1982.

Provides a review of the basic successful efforts and full cost rules. It is written from the perspective of a nonaccountant, although it provides the general rules for practicing accountants. Also included are sample annual reports and the complete successful efforts and full cost rules.

Moore, Cecil H., and Grier, James D. *Accounting Standards and Regulations for Oil and Gas Producers.* Englewood Cliffs, N.J.: Prentice-Hall, Inc., 1983.

Reference guide for the explanation of standards and regulations promulgated by the FASB and SEC. Contains numerous practical examples. Successful efforts and full cost methods are both discussed with overview of development of current standards and regulations.

Norton, John C., and Rowe, Donald A. *United Kingdom Oil and Gas Exploration and Production.* London: The Institute of Chartered Accountants of England and Wales, 1978.

Provides a general introduction to the various accounting practices followed by companies engaged in oil and gas exploration and production in the United Kingdom. While describing various alternative accounting practices followed in the industry, the book also serves as a practical handbook for those in financial management and provides the theoretical background required by those involved in the financial reporting of the industry.

Porter, Stanley P. *Petroleum Accounting Practices.* New York: McGraw-Hill Book Company, 1965.

A general reference book on oil and gas accounting. Accounting principles for exploration, development, and production are covered. In addition, the book includes chapters on tank car operations, pipeline operations, marine operations, crude oil purchasing and storage, refining operations, petrochemical operations, and marketing operations.

Welsch, Glenn A., and Deakin, Edward B. *Measuring and Reporting the "Replacement" Cost of Oil and Gas Reserves: A Research Study.* Washington, D.C.: American Petroleum Institute, 1977.

A research study sponsored by the API on methods to compute value of oil and gas reserves.

Books—General

Baker, Ron. *Primer of Oilwell Drilling.* 4th ed. Austin, Texas: Petroleum Extension Service, University of Texas; in cooperation with International Association of Drilling Contractors, 1979.

A good description of physical activities in selecting drilling sites, carrying on drilling activities, completing wells, and performing special drilling operations. Includes a description of drilling rig components.

Petroleum Extension Service. *A Dictionary of Petroleum Terms.* 2d ed. Austin, Texas: Petroleum Extension Service, University of Texas, 1979.

Coverage includes not only petroleum industry terms but abbreviations used in drilling reports and abbreviations used for scientific and engineering terms.

________. *Fundamentals of Petroleum.* 2d ed. Austin, Texas: Petroleum Extension Service, University of Texas, 1981.

Designed to serve as a basic guide on the practical aspects of the petroleum industry. Gives a basic discussion of the petroleum industry from geology and reservoirs through exploration, drilling, production, pipelining, refining, and marketing.

________. *Primer of Offshore Operations.* Austin, Texas: Petroleum Extension Service, University of Texas, 1976.

Principally discusses the equipment and methods used to solve problems encountered in offshore operations.

________. *Primer of Oil and Gas Production.* 3d ed. Austin, Texas: Petroleum Extension Service, University of Texas, 1976.

Designed for the person unfamiliar with production practices. Gives an elementary understanding of the day-to-day workings of an oil and gas field.

________. *Primer of Oilwell Service and Workover.* 3d ed. Austin, Texas: Petroleum Extension Service, University of Texas; in cooperation with the Association of Oilwell Servicing Contractors, 1979.

Scope includes equipment and procedures used in oil well service. Specific chapters include well completion, remedial well work, well cleanout and work-over, well stimulation and analysis, planning, and economics. Contains glossary of terms used.

Williams, Howard R., and Meyers, Charles J. *Manual of Oil and Gas Terms.* 5th ed. New York: Matthew Bender & Co., Inc., 1981.

Comprehensive listing of oil and gas terms with short, concise definitions that often include references to statutes, cases, books, and law review articles. Revised annually.

Books—Taxation

Burke, Frank M., Jr., and Bowhay, Robert W. *Income Taxation of Natural Resources.* Englewood, N.J.: Prentice-Hall, Inc., 1982.

A general coverage of oil and gas taxation. Revised annually.

Houghton, James L.; Crawford, Robert F.; Gaar, James R.; and Braden, John R. *Miller's Oil and Gas Federal Income Taxation.* Chicago: Commerce Clearing House, Inc., 1981.

A general coverage of oil and gas taxation. Revised frequently.

COPAS Bulletins

COPAS Bulletins are issued by the Council of Petroleum Accountants Societies. The bulletins, listed below by number, provide accounting guidance in matters related to joint operations. They may be purchased from Kraftbilt Products, P.O. Box 800, Tulsa, Okla. 74101.

1. *Classifications for Use in Summary Form Billing-Producing and Gasoline Plant Operations.* 1963. 32 pages.
2. *Determination of Values for Well Cost Adjustments—Joint Operations.* 1965. 8 pages.
3. *The Initiation of Joint Account Audits.* 1962. 12 pages.
4. *COPAS Forms.* rev. ed., 1974. 34 pages.
5. *Accounting Procedure—Joint Operations.* 1966. 24 pages.
6. *Material Classification Manual.* 1971. 20 pages.

7. *Gas Accounting Manual.* rev. ed., 1981. 105 pages.
8. *Accounting Procedure—Joint Operations.* 1969. 43 pages.
9. *Accounting for Farmouts / Farmins, Net Profits Interests and Carried Interests.* 1969. 8 pages.
10. *Petroleum Industry Accounting Educational Training Guide.* 1971. 32 pages.
11. *Accounting for Unitizations.* 1971. 31 pages.
12. *Computer Production Control Accounting Guidelines.* 1975. 34 pages.
13. *Accounting Procedure—Joint Operations.* 1975. 23 pages.
14. *Accounting Procedure—Arctic Operations.* 1974. 13 pages.
15. *Accounting Procedure—Offshore Joint Operations.* 1977. 25 pages.
16. *Overhead—Joint Operations.* 1980. 18 pages.
17. *Oil Accounting Manual.* 1981. 69 pages.
18. *Distribution of Boat and Fuel Expenses—Offshore Operations.* 1981. 16 pages.
19. *Distribution of Helicopter Expenses—Offshore Operations.* 1983. 14 pages.

COPAS Interpretations

Interpretations of portions of COPAS Bulletins that are subject to debate.

Periodicals

Journal of Extractive Industries Accounting. Denton, Texas: Professional Development Institute, North Texas State University.

Published three times a year. Articles deal primarily with financial accounting and reporting problems in the petroleum industry.

Oil and Gas Tax Quarterly. New York: Matthew Bender & Co., Inc.

Published quarterly. Most articles are related to oil and gas taxation, with a few articles on financial accounting and reporting in the petroleum industry.

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